enerPLUS
RESOURCES FUND

annual report **2006**

we are energy

plus

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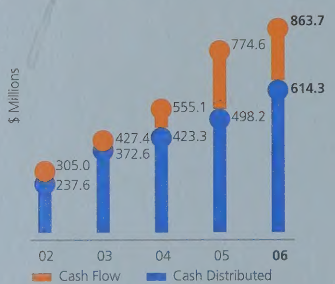
strategy

it's the energy of **enerplus**

Enerplus Resources Fund is Canada's oldest and one of North America's largest conventional oil and gas income funds. Established in 1986, we have grown our business from a $9 million initial public offering to a market capitalization of over $6 billion today. Since inception, we have provided investors the opportunity to participate in an income-generating investment within the energy industry that distributes cash monthly from the sale of our oil and natural gas production. We are committed to providing investors with a superior return on their investment and will continue to seek opportunities that create value and enhance the sustainability of our business over the long-term.

Cash flow from operations increased by 11% in 2006 despite modest weakness in commodity prices.

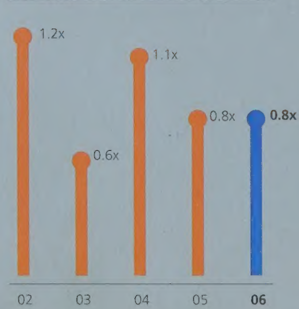
Cash Flow from Operations [1]



[1] Cash flow from operations includes changes in non-cash working capital

Our balance sheet remains strong allowing for greater flexibility.

Debt to Cash Flow [1]



[1] Debt/trailing 12 month cash flow ratio

financial and operating highlights

Financial highlights

For the years ended December 31,	2006	2005
Financial (000's)		
Net Income	$ 544,782	$ 432,041
Cash Flow from Operating Activities	863,696	774,633
Cash Distributions to Unitholders [1]	614,340	498,205
Cash Withheld for Acquisitions and Capital Expenditures	249,356	276,428
Debt Outstanding (net of cash)	679,650	649,825
Development Capital Spending	491,226	368,689
Acquisitions	51,313	704,028
Divestments	21,127	66,511
Financial per Unit [2]		
Net Income	$ 4.48	$ 3.96
Cash Flow from Operating Activities	7.10	7.10
Cash Distributions to Unitholders [1]	5.05	4.57
Cash Withheld for Acquisitions and Capital Expenditures	2.05	2.53
Payout Ratio [3]	71%	64%
Selected Financial Results per BOE [4]		
Oil & Gas Sales [5]	$ 50.23	$ 52.36
Royalties	(9.36)	(10.21)
Financial Contracts	(1.10)	(4.90)
Operating Costs	(8.02)	(7.45)
General and Administrative	(1.71)	(1.28)
Interest and Foreign Exchange	(0.93)	(0.64)
Taxes	(0.70)	(0.31)
Restoration and Abandonment	(0.37)	(0.27)
Cash Flow from Operating Activities before changes in non-cash working capital	$ 28.04	$ 27.30
Weighted Average Number of Trust Units Outstanding (thousands)	121,588	109,083
Debt/Trailing 12 Month Cash Flow Ratio	0.8x	0.8x

In some circumstances, presentation has been changed to minimize the use of non-GAAP measures.

[1] Calculated based on distributions paid or payable. Cash distributions to unitholders per unit will not correspond to the actual monthly distributions of $5.04 as a result of using the annual weighted average trust units outstanding.

[2] Based on annual weighted average trust units outstanding.

[3] Calculated as Cash Distributions to Unitholders divided by Cash Flow from Operating Activities.

[4] Non-cash amounts have been excluded.

This Annual Report contains forward-looking information and statements within the meaning of applicable securities laws. See "Forward-looking Information and Statements" in our Management's Discussion and Analysis contained in this Annual Report, which section applies in all respects to all forward-looking information and statements contained in this Annual Report. Readers are urged to review the Definitions and Abbreviations section included at the end of this report for information on definitions and the methodology used in determining various metrics.

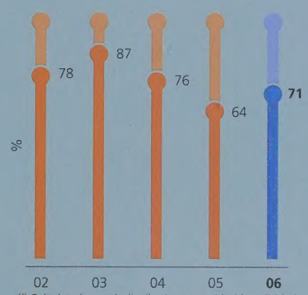
Operating highlights

For the years ended December 31,	2006	2005
Average Daily Production		
Natural gas (Mcf/day)	270,972	274,336
Crude oil (bbls/day)	36,134	29,315
NGLs (bbls/day)	4,483	4,689
Total (BOE/day)	85,779	79,727
% Natural gas	53%	57%
Average Selling Price [5]		
Natural gas (per Mcf)	$ 6.81	$ 8.41
Crude oil (per bbl)	61.80	55.93
NGLs (per bbl)	50.90	47.33
Per BOE	50.23	52.36
US$ exchange rate	0.88	0.83
Net Wells drilled	361	393
Success Rate	99%	99%
Proved Reserves (MMBOE) [6]	299.8	313.2
Probable Reserves (MMBOE) [6]	143.5	135.9
Total Proved plus Probable Reserves (MMBOE) [6]	443.3	449.1
FD&A Cost/BOE, excluding Future Development Capital [7]	$ 20.45	$ 13.98
FD&A Cost/BOE, including Future Development Capital [7]	$ 23.19	$ 17.18
Recycle Ratio [7]	1.4x	1.7x
Proved Reserve Life Index (years) [7]	10.1	9.9
Proved plus Probable Reserve Life Index (years) [7]	14.0	13.5

(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(6) Reserve figures are calculated based upon company interest reserves using forecast prices and costs.
(7) Based upon proved plus probable company interest reserves.

We continued to reinvest a significant amount of cash flow into our assets.

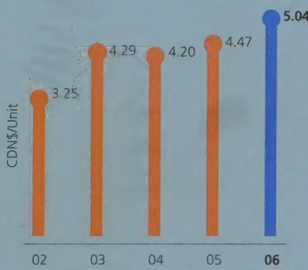
Payout Ratio[1]



(1) Calculated as cash distributions to unitholders divided by cash flow from operating activities.

Cash distributions to unitholders increased by more than 13% per unit in 2006.

Cash Distributions to Unitholders [1]



(1) Cash distributions from the Consolidated Statements of Cash Flows includes amounts paid or declared during the year

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our people

president's message

The year 2006 marked another year of significant operational and financial success for Enerplus, but it was also impacted by the surprise announcement on October 31, 2006 by the Canadian federal government to completely reverse their position of one year ago that they would not impose a tax on trusts, such as Enerplus. While I will elaborate more on this action by the government, I want to first highlight that our primary business and focus has remained unchanged. We are committed to being a strong, technical oriented oil and gas company. Evidence of this commitment to being a top oil and gas producer is found throughout our 2006 annual report.

In 2006 we completed our most ambitious capital program in our 20 year history, spending just over $491 million on our oil and gas activities. During 2006 we adjusted the allocation of our capital spending to focus on our higher return opportunities in response to cost inflation, significantly lower natural gas prices and strong oil prices. We shifted more of our spending to projects such as our Bakken oil development in Montana and reduced our shallow gas and coal bed methane programs in western Canada. As a result of our spending, we increased our production to an average of 85,779 BOE per day, up approximately 8% from last year, and increased both our cash flow from operations and distributions per unit by 11% and 13% respectively over the previous year. Cost inflation pressures, however, continued to impact on our operations in 2006 as they did industry wide. We experienced increases in our operating, general and administration and finding, development and acquisition costs per BOE compared to 2005. Also, while we are seeing some softening in inflationary pressures, competition for people and services remains tight.

The following recaps our key accomplishments for 2006:

- Cash distributions to unitholders were maintained throughout the year at $0.42 per unit resulting in total distributions of $5.04 per unit, a 13% increase over distributions paid to unitholders in 2005.
- Our annual average production rate exceeded our guidance and grew to 85,779 BOE/day primarily as a result of our internal capital program. This demonstrated our ability to grow production from our internal development program without reliance on acquisitions. Our exit rate volumes were also in line with our expectations at 87,500 BOE/day.
- We executed a $491.2 million development capital program essentially in line with our target of $485.0 million. Through this spending, we drilled 361 net wells with a success rate of over 99%.
- Cash flow increased 11% to $863.7 million in 2006 from $774.6 million in the previous year with 71% distributed to unitholders.
- Our Reserve Life Index continues to be one of the longest in the sector at 14.0 years on a proved plus probable basis and 10.1 years on a proved basis, including both conventional and non-conventional reserves.
- Our finding, development and acquisition costs ("FD&A") for the year were $23.19/BOE on a proved plus probable basis and $28.82/BOE on a proved basis including future development capital ("FDC"). Excluding FDC our proved plus probable FD&A costs were $20.45/BOE and $29.13/BOE on a proved basis. Our three-year proved plus probable FD&A costs were $14.90/BOE ($11.51/BOE excluding FDC).

In 2006 we completed our most ambitious capital program in our 20 year history.

Gordon J. Kerr
President & Chief Executive Officer

Garry A. Tanner
Executive Vice President
& Chief Operating Officer

Robert J. Waters
Senior Vice President
& Chief Financial Officer

Ian C. Dundas
Senior Vice President,
Business Development

- We replaced 82% of our produced reserves without the benefit of any significant acquisitions, ending the year with proved plus probable reserves of 443.3 MMBOE (down 1%) and proved reserves of 299.8 MMBOE (down 4%).
- We continue to maintain a conservative balance sheet as evidenced by a net debt to trailing 12 month cash flow ratio of 0.8 times.

In addition to our operational and financial achievements in 2006, we also completed an in depth review of our conventional asset base resulting in an assessment that identifies approximately $2 billion of potential capital projects within our conventional asset base. This represents approximately 2,500 net drilling locations or roughly five years of conventional future development potential at current spending levels. These projects will support our operations in the years ahead through the development and addition of production and reserves.

In addition to our conventional activities, we continued to advance on the Joslyn mine project. Our operating partner is in the process of responding to the supplemental information requests ("SIR's") in respect of the North Mine application. We are hopeful that regulatory approval to proceed with the North Mine development will be received in 2007. This could put us in a position to be able to record probable reserves in respect of the North Mine in 2007. An independent engineering assessment has determined Enerplus' 15% interest in the North Mine represents 140 million barrels of resource potential.

Also, with respect to the Joslyn lease overall, we are in the process of developing the optimal lease development plan with our operating partner. This could result in more of the lease being targeted for mining extraction versus Steam Assisted Gravity Drainage ("SAGD") extraction. Mining extraction could result in higher ultimate recovery of the resource contained within the Joslyn lease area.

In addition to progressing on the Joslyn project, we have also put in place a team of professionals with significant SAGD assessment and operating execution skills. It is our intent to pursue an operated SAGD project as part of our long-term growth and sustainability strategy.

In the U.S. we completed the staffing of our Denver office and the full integration of operations in 2006. As a result, we achieved significant success on the execution of an expanded drilling program at Sleeping Giant, our major producing property in Montana. Our production of light sweet crude oil and natural gas out of the Sleeping Giant field grew from approximately 9,400 BOE per day in 2005 to average 11,300 BOE per day in 2006.

Commodity Prices

In 2006, natural gas and crude oil prices were influenced by the standard set of factors: weather, geopolitical risk, inventory positions, economic expansion, investment in production, and the cost of substitute fuels.

As we came out of a warm winter with high gas inventories, a subdued hurricane season ultimately drove the AECO monthly index price to a low for the year of $4.45/Mcf in October. Spot and forward prices recovered significantly as winter approached, with

spot prices rising briefly above $8.00/Mcf before a warmer than normal November and December pushed the daily spot price back to $6.07/Mcf on December 31, 2006. Currently, the forward curve for 2007, influenced by cold weather in late January and early February, has regained strength and is in the range of $8.00/Mcf.

World crude oil prices continued to be influenced by strong demand and geopolitical events through the first half of 2006, continuing the upward trend in prices experienced during 2005. WTI spot prices peaked in July during the Israel-Hezbollah conflict at US$77.03/bbl. With strong inventories, warmer than normal weather conditions expected for the winter, and continued strength on the supply side, prices fell thereafter through the second half of 2006. The WTI spot price hit a low of US$55.81/bbl in November, representing a 28% reduction from the July high. Late in the year OPEC agreed to cut production in order to better balance supply and demand, with the objective of protecting the WTI price from falling much below US$55/bbl. OPEC's actions, combined with cold weather in late January and February, has stabilized the price somewhat and the forward price for 2007 has now recovered to just above US$60/bbl.

During 2006, our strategy of maintaining a mix of oil and gas in our portfolio proved beneficial in maintaining our distributions. Strong oil prices combined with the reallocation of our capital spending away from gas projects towards our more profitable oil projects helped us offset the impacts of a reduced gas price. As a result, we maintained our distributions at 42 cents per unit while others were cutting their distributions largely as a consequence of lower gas prices.

We continue to remain bullish on oil and gas prices in the long term, however, we expect to experience volatility in the short term. We intend to continue with our price risk management strategies in 2007 as discussed more fully under the heading "Price Risk Management" in this report.

Government and Regulatory Developments

Taxation of Trusts

On October 31, 2006 the Finance Minister of Canada announced a plan which, among other things, would impose a 31.5 percent tax on certain income flows generated within trust entities. For existing trusts such as Enerplus, the tax would be imposed commencing in the year 2011. The announcement came as a surprise to financial markets and all concerned as it represented a complete reversal of the position taken by the ruling Conservative Party less than 12 months earlier. For Enerplus unitholders the immediate impact was to erode what would have been a double digit total return for the year to essentially zero.

Since the announcement, a Ways and Means Motion has been passed in the Canadian House of Commons. Enabling legislation has been drafted but, as at the time of this report, has yet to be introduced into the House of Commons. Enabling legislation requires three readings and passage in the House of Commons as well as subsequent passage in the Senate before it becomes fully implemented. In the interim period, the House of Commons Standing Committee on Finance has held a series of special hearings on the plan to tax

Jo-Anne M. Caza
Vice President, Investor Relations

Rodney D. Gray
Vice President, Finance

Larry P. Hammond
Vice President, Operations

Lyonel G. Kawa
Vice President, Information Services

Jennifer F. Koury
Vice President, Corporate Services

Eric G. Le Dain
Vice President, Marketing

trusts. The Committee has released a report dated February 2007 which concludes with their recommendations essentially as follows:

1) That the federal government release the data and methodology that it used to estimate the amount of federal tax revenue loss caused by the income trust sector;

2) That the proposal to tax income trusts is of such significance that it should be brought to vote as a separate piece of legislation distinct from other sections contained within the original Ways and Means Motion; and

3) The federal government reduce its proposed 31.5% Distribution Tax on income trusts to 10%. This tax should be instituted immediately and made refundable to all Canadian investors. Furthermore, the government should continue the moratorium on new income trust conversions while remaining open to representations from sectors that feel they are well suited to the income trust structure; or the federal government extend the proposed transition period from 4 years to 10 years.

Immediately after the government's October 31 announcement Enerplus joined with other members of the energy trust sector to form the Coalition of Canadian Energy Trusts ("CCET"). Our primary purpose has been to bring forward factual arguments in support of an exemption for energy trusts from the government's proposed tax plan. We have conducted numerous meetings with federal politicians, media representatives and members of the analyst and investment community in an effort to deliver information and analyses we believe was totally lacking in the government's development of their tax policy on this matter. We believe these efforts, together with those of others directly impacted, including the millions of investors in trusts, resulted in the special hearings conducted by the House of Commons Standing Committee on Finance. Time will tell whether or not these efforts will have positive results.

Greenhouse Gas Emissions and Climate Change

A considerable amount of dialogue and action has developed internationally, nationally and locally on the issue of greenhouse gas emissions and connectivity to concerns over global climate change. The debate over the science of the issue has fallen to the wayside, particularly with the recent pronouncements coming out of the Intergovernmental Panel on Climate Change. While Canada had previously ratified its participation in the "Kyoto Accord", no legislation had been put in place to enforce change to accomplish the target reductions encompassed within the Accord. The targets have been widely considered unattainable by the business community without wreaking havoc on our economy. The question has now moved from "will regulations be put in place to reduce greenhouse gas emissions?" to "what form will emission reductions take, how will emission reductions be achieved, and how will the costs be shared?".

Currently, Enerplus has minimal exposure to large facility emitter (LFE's) classes of facilities, however, future facilities associated with our Joslyn Creek mining development could fall into this category. We believe LFE's will be the first facilities to be impacted by any legislated government changes.

It is expected that policy at both the federal and provincial levels will be unveiled in the first half of 2007. The energy industry is keenly awaiting this unveiling to determine its impact on current operations and future developments.

Alberta Royalty Review

In December, 2006 the Alberta provincial government announced plans for a review of royalty structures in Alberta for both Crown owned conventional and unconventional oil and natural gas resources. A review panel consisting of economists, academics and former industry participants has been formed by the Minister of Finance. While no conclusions can be reached at this point as to the outcome of this review it was widely speculated that the rapid pace and magnitude of development in the Alberta oil sands combined with the public's perception of a 1% royalty on revenue before payout of oil sands projects served as the catalyst for this review.

Approximately 70% of the royalties currently paid by Enerplus is to the Alberta government and in respect of conventional production. We do not expect a significant impact on our current operations coming out of this review but will have to await the results to make a proper determination. The government's review is expected to be concluded by August 2007 with findings and conclusions published shortly thereafter.

2007 Outlook

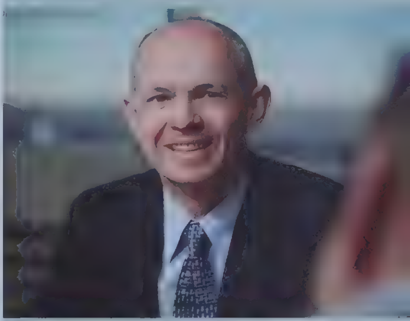
As we move forward into 2007 Enerplus is well positioned both operationally and financially to meet the challenges that face us in 2007. We will obviously be seeking greater clarity on the federal government's taxation proposals, greenhouse gas emission initiatives by various governments and the Alberta government's royalty review initiative to determine their impacts on Enerplus' longer term strategic plans.

For 2007 we have reduced our capital spending plans by approximately 16% compared to 2006, further high grading our spending on shallow gas and CBM projects and reflecting a lower spending requirement on our Bakken oil play in Montana. We expect to maintain our production in the order of 85,000 BOE per day and exit 2007 at approximately 86,000 BOE per day based upon spending $410 million on our capital programs and before considering any acquisitions we may make.

As previously mentioned, we are seeing some signs of a softening in cost escalation pressure for supplies and services as capital expenditure programs have been reduced in the Canadian oil and gas sector, particularly on the natural gas side. However, the labour supply situation remains tight and a rebound in natural gas prices and associated activity could quickly reverse the trend.

We will continue to expand our exposure to large repeatable resource type plays in both Canada and the U.S. In addition to expanding our technical capabilities in the area of oil sands SAGD operations and continuing to employ our shallow gas and waterflood expertise, we are also focusing on developing our deep gas capabilities.

David A. McCoy
Vice President, General Counsel
& Corporate Secretary



Daniel M. Stevens
Vice President, Development Services

I strongly encourage interested investors to read our annual report in its entirety for a full review of our 2006 activities and future plans.

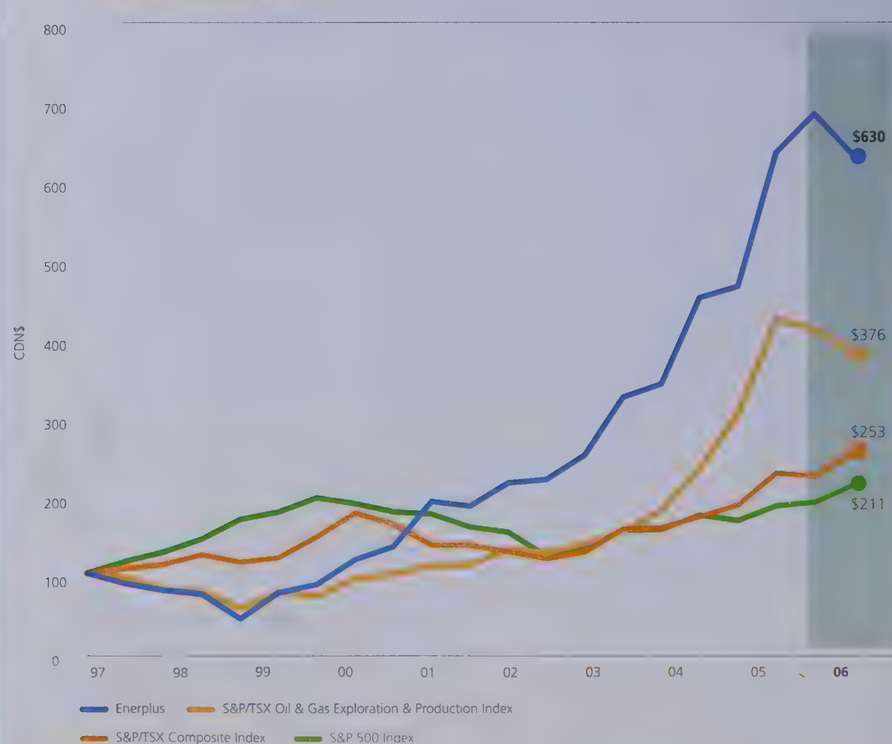
As a final note, I once again extend my thanks to our Board of Directors for their guidance and support throughout the year. I also extend my thanks to our staff for their diligence in the conduct of all aspects of our operations and to our investors who have continued to support us as we move forward into 2007.

Enerplus is a strong oil and natural gas company well positioned through our assets, strategies and people to succeed now and into the future.

Gordon J. Kerr
President & Chief Executive Officer

We will continue to advance our efforts to expand our exposure to large repeatable resource type plays in both Canada and the U.S.

10 Year Compound Return



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our strategy

our strategy

Our long reserve life index continues to be one of our key competitive advantages.

Reserve Life Index (1)

(1) Calculated using proved plus probable reserves for 2003-2006. Prior years reflect established reserves.

At Enerplus, we are focused on being a top-tier oil and gas producer. To achieve this, we have built a technically driven organization marked by highly qualified staff, strategic long-life assets, consistent execution and delivery of key operating results, a robust set of future opportunities and clear competitive advantages. These efforts will serve us well regardless of our organizational structure.

This focus delivered strong results in 2006:

- Annual average daily production and exit rate volumes in line with our forecast
- Production growth from internal development
- Record capital development with attractive efficiencies of under $23,000/BOE/day
- Positive reserve additions from our U.S. assets contributed to replacing 82% of our production without the benefit of any significant acquisitions
- One-year proved plus probable FD&A cost of $23.19/BOE reflecting inflationary pressures on our development program. Our three-year FD&A costs are $14.90/BOE ($11.51/BOE excluding future development capital)
- A significant increase in our future opportunity set to $2 billion in attractive conventional capital projects and $1 billion in oil sands projects excluding any upgrading options.

Within the oil and gas industry, we compete for people, land, services, supplies, and new ideas. To operate successfully, we have developed the following competitive advantages:

- Resource-play focus. Approximately 50% of our conventional asset base consists of resource plays which are marked by relatively predictable decline rates with low geologic risk. They offer significant development potential with improving economics as a result of technology and experience.
- Long-life, low decline reserves. Our proved plus probable reserve life index of 14 years is one of the longest in the sector. That translates into lower base declines and allows us to be selective with our capital investments and acquisitions.
- Diverse assets. Exposure to a variety of oil and gas assets reduces the risk associated with any one property and provides valuable insights across the industry, allowing us to capitalize on other new opportunities. Our balanced commodity mix also provides exposure to both crude oil and natural gas, reducing our risk to lower prices in any one commodity.
- Size and execution capabilities. Our size gives us the capability to execute large programs while leveraging our purchasing power. Establishing partner-oriented relationships with our suppliers helps ensure efficient execution of our activities.
- Robust future opportunity set. Our five-year inventory of conventional projects and the diversity of these projects positions us to maintain and grow production without relying on acquisitions. It also provides flexibility to manage through varying commodity price cycles.
- Our team. Enerplus has a strong team with demonstrated effectiveness on operations, conventional development and M&A. In 2006 we built a U.S. team that delivered superior results on the acquisitions from 2005 and an oil sands team that includes personnel with experience on most major oil sands projects in Alberta.

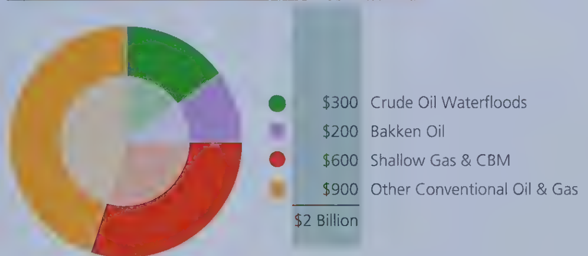
our potential

Enerplus has focused on building a large, diversified portfolio of economic, conventional and non-conventional capital projects that will support our operations in the years ahead through the addition of production and reserves. We currently have a conventional opportunity set of approximately $2 billion of capital projects representing approximately 2,500 net wells. The non-conventional opportunities are estimated at approximately $1 billion of capital projects associated with oil sands excluding any investments relating to an upgrader solution. This represents about five years of conventional future development potential at current capital spending levels assuming no new acquisitions, land deals, or new opportunity identification on our existing properties.

Our opportunity set includes significant potential across our entire asset base and capital projects which are both technically and economically viable at today's commodity prices:

- Weighted 60% to natural gas and 40% to oil
- Resource plays comprise over 50% of the total
- Includes approximately $500 million of opportunity included in our third party reserve engineering reports
- $1 billion of "base" projects which we project to have a greater than 80% chance of technical success
- Approximately $500 million of risk-adjusted opportunities that have less than an 80% chance of success

Future Conventional Opportunities ($ millions)



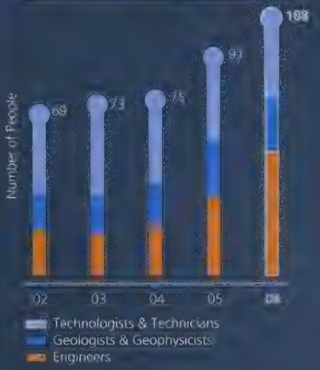
We have excluded those projects from our opportunity set that are early stage ideas with greater technical/economic uncertainty.

This opportunity set has grown significantly over the last few years as a result of strong commodity prices and the following focused efforts:

- Increasing our technical abilities and staffing levels have added the necessary expertise in-house to recognize and unlock the value of our assets in the future.
- Over the last two years we have spent 15 – 20% of our capital expenditures program (about $150 million) on long-term investment opportunities which were not expected to increase cash flow in the current year, including approximately $70 million on oil sands. Almost $50 million was spent on new land and seismic, and $30 million was spent on exploration activities. We have a number of evolving grassroots resource plays being evaluated in 2007 as well as approximately $30 million of new development projects as a result of the investments made in 2005 and 2006.

Our increasing complement of technical staff helps unlock value from our assets.

Technical Staffing Levels



our operations

Average annual production volumes increased in 2006 as a result of our internal development program and a full year of our U.S. acquisitions.

Annual Average Production

2006 Production

In 2006, we were able to grow the production from our assets as a result of the successful execution of the largest development capital program in our history and strong base performance. Daily production averaged 85,800 BOE/day, a new high for Enerplus and slightly ahead of our guidance of 85,500 BOE/day. Strong base production performance from our U.S. and Canadian operations and production additions from our capital program resulted in an increase in our year-over-year exit rate from 85,000 BOE/day in 2005 to 87,500 BOE/day in 2006, demonstrating our ability to grow production through internal development without the benefit of any significant acquisition activity.

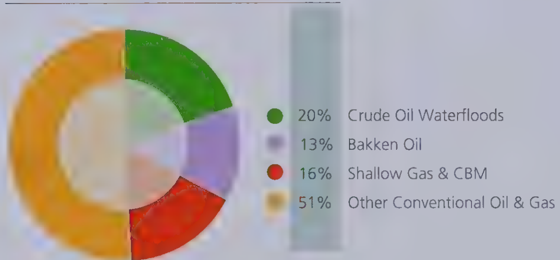
Approximately 50% of our average daily production volumes are attributed to resource plays, with the Sleeping Giant project in Montana now our single largest producing property. We continue to operate approximately 64% of our daily production volumes.

We expect 2007 average production to remain essentially flat at 85,000 BOE/day with a reduced capital program of $410 million. We expect to exit 2007 with daily production of 86,000 BOE/day as a result of the timing of our capital expenditures which are back-end loaded. These targets are exclusive of any acquisition or divestment activity that may occur as a normal part of our business.

2006 Capital Spending

Development capital spending of $491 million during 2006 was in line with our guidance of $485 million despite industry inflationary pressures. Through this spending, we added approximately 21,400 BOE/day of initial production at an attractive on-stream cost of $23,000/BOE/day which is significantly better than our on-stream cost in 2005 and was slightly better than expected. We achieved these results due to the strength of our opportunity set and our ability to allocate capital to our most attractive projects. Our capital high-grading in 2006 included increasing our Bakken oil spending and deferring some of our less attractive shallow gas and waterflood projects.

Production by Resource Play



Key attributes of our 2006 capital program include:

- We achieved better than expected capital efficiencies despite inflationary pressures. Inflation averaged approximately 15%, meaningfully higher than anticipated. As a result we chose to defer approximately 10% of our planned activity to manage our capital spending while maintaining attractive capital efficiencies.
- Approximately 57% of our capital was directed to oil development while 43% was directed to natural gas opportunities reflecting the strength of the oil markets and the attractiveness of our Bakken oil development in the U.S.
- 64% of our capital spending was focused on resource plays.
- We also invested approximately $89 million (18% of our total capital) in longer-term opportunities in oil sands, land, seismic and higher risk drilling activities which did not add production or cash flow in the current year but positions us to add significant production and reserves over the next few years.
- Operated capital spending accounted for 73% of the total which is higher than last year due to higher spending on our U.S. Bakken oil projects.

Play Type	2006 Initial Production Additions* (BOE/day)	2006 Capital ($ millions)	2006 Cost of Production Additions ($/BOE/day)	2007 Estimated Capital ($ millions)
Shallow Gas & CBM	3,200	$ 94	$29,400	$ 43
Crude Oil Waterfloods	1,600	66	41,250	65
Bakken Oil	7,800	117	15,000	70
Oil Sands (SAGD/mine)	–	39	n/a	40
Other Conventional Oil & Gas	8,800	175	19,900	192
Total	**21,400**	**$491**	**$23,000**	**$410**

* 2006 production was not recorded for Joslyn as the operation has not reached commercial production levels. Based on first-month production rates.

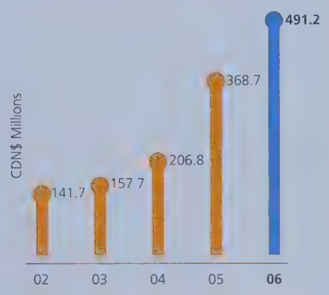
2007 Capital Spending

Capital spending has been reduced to $410 million for 2007 based on our current commodity price outlook. Should commodity prices change and/or if we experience better success, our capital budget could increase or decrease. Our spending will continue to be focused on resource play development. We also expect to spend $84 million (20%) on longer-term opportunities in oil sands, land, seismic and higher risk drilling.

The most significant reductions in our program will occur in our shallow gas/CBM program and U.S. Bakken spending. The shallow gas/CBM program was deferred given potential risks we see with near-term gas prices although with continued gas price strength, these programs could be increased. Currently, we plan to continue with a base level program concentrating on our most profitable opportunities in this area as it is a core activity for us and represents a significant percentage of our future opportunity. The reduction in our U.S. Bakken spending reflects the completion of a majority of our drilling program of two wells per section. We are currently testing the benefits of a third well per section, exploring other zones in the area as well as extending the Bakken play into North Dakota. With success in these areas, we could increase our U.S. spending.

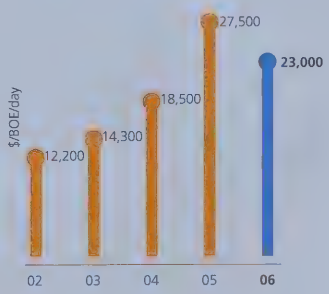
Development spending has been increasing as our internal opportunities expand.

Development Capital Spending



Our capital efficiency improved in 2006 by nearly 17%.

Capital Efficiency *



* Cost per BOE based on first month production rates

Average annual production volumes increased in 2006 as a result of our internal development program and a full year of our U.S. acquisitions.

Annual Average Production

our operations

2006 Production

In 2006, we were able to grow the production from our assets as a result of the successful execution of the largest development capital program in our history and strong base performance. Daily production averaged 85,800 BOE/day, a new high for Enerplus and slightly ahead of our guidance of 85,500 BOE/day. Strong base production performance from our U.S. and Canadian operations and production additions from our capital program resulted in an increase in our year-over-year exit rate from 85,000 BOE/day in 2005 to 87,500 BOE/day in 2006, demonstrating our ability to grow production through internal development without the benefit of any significant acquisition activity.

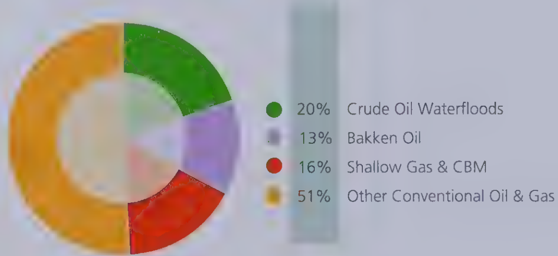
Approximately 50% of our average daily production volumes are attributed to resource plays, with the Sleeping Giant project in Montana now our single largest producing property. We continue to operate approximately 64% of our daily production volumes.

We expect 2007 average production to remain essentially flat at 85,000 BOE/day with a reduced capital program of $410 million. We expect to exit 2007 with daily production of 86,000 BOE/day as a result of the timing of our capital expenditures which are back-end loaded. These targets are exclusive of any acquisition or divestment activity that may occur as a normal part of our business.

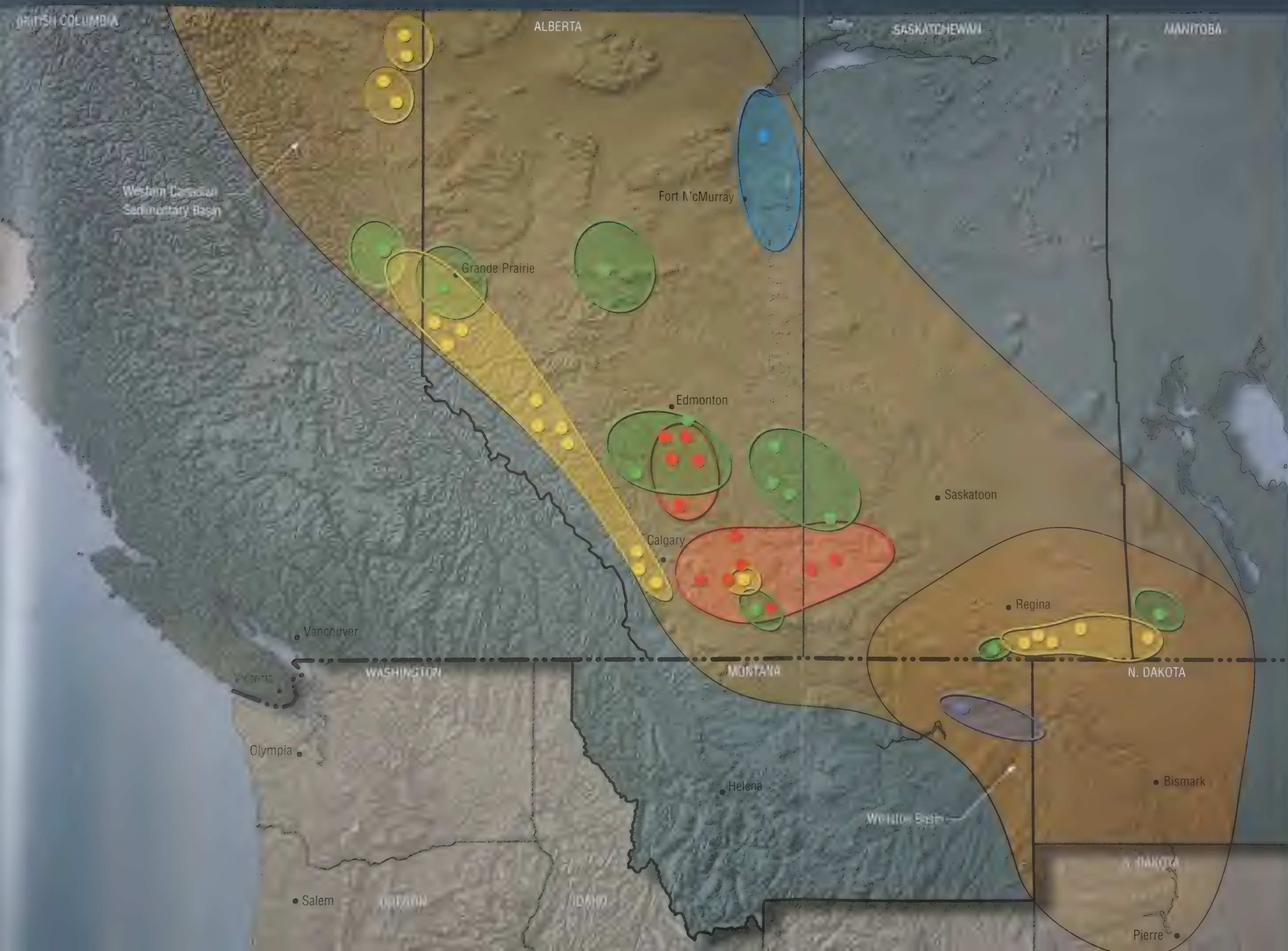
2006 Capital Spending

Development capital spending of $491 million during 2006 was in line with our guidance of $485 million despite industry inflationary pressures. Through this spending, we added approximately 21,400 BOE/day of initial production at an attractive on-stream cost of $23,000/BOE/day which is significantly better than our on-stream cost in 2005 and was slightly better than expected. We achieved these results due to the strength of our opportunity set and our ability to allocate capital to our most attractive projects. Our capital high-grading in 2006 included increasing our Bakken oil spending and deferring some of our less attractive shallow gas and waterflood projects.

Production by Resource Play



our resource plays



Crude Oil Waterfloods

- Represents 25% of our daily production
- Predictable secondary recovery schemes with low decline rates and significant original oil in place

Bakken Oil

- Produces over 11,500 BOE/day or 13% of our current production
- 42 degree API light oil with low operating costs

Oil Sands

- Enerplus is one of the few conventional oil and gas trusts with a significant interest in the oil sands
- Sizeable mining and SAGD development potential

Shallow Natural Gas & CBM

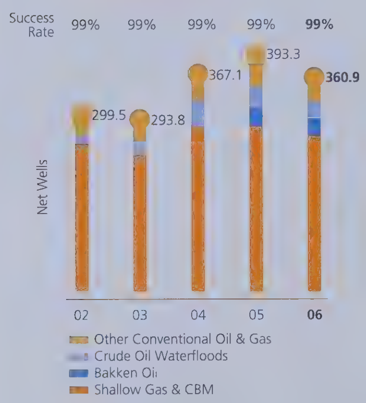
- Together these two resource plays account for 16% of our daily production
- Both shallow gas and CBM are characterized by low risk, repeatable drilling opportunities

Other Conventional Oil & Gas

- Includes a variety of both operated and non-operated oil & gas production
- Diverse property set provides numerous development opportunities

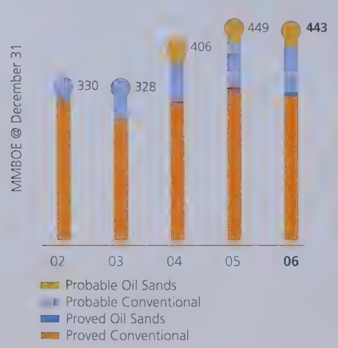
We maintained an active drilling program in 2006 with a 99% success rate.

Drilling Activity



Total reserve volumes were essentially flat year-over-year.

Proved plus Probable Reserves



2006 Drilling Activity

In 2006, we participated in the drilling of 360.9 net wells, significantly less than our original guidance of 550 net wells, while maintaining our success rate of 99%. During the course of the year, we elected to defer a portion of our drilling program as a result of industry inflationary pressures and lower natural gas prices. We deferred the drilling of approximately 140 net shallow gas and CBM wells, approximately 30 net waterflood wells and 20 other net wells. Funds from these programs offset the inflationary pressures on the remainder of the drilling program and ensured the execution of other more profitable drilling programs such as those in our Bakken oil and other conventional drilling programs. In total we drilled 275.1 net natural gas wells and 85.8 net crude oil wells in 2006.

As commodity prices have increased, especially crude oil prices, we have expanded our asset base into new regions and resource plays. We have seen a trend toward the drilling of deeper and more technically challenging wells. We see this as a necessary competitive advantage going forward as we work to unlock the opportunity available within these new resource plays. As illustrated in our drilling chart, our shallow gas/CBM program which has historically dominated our drilling program has declined due to natural gas price weakness in 2006 and the growth of drilling in more challenging oil areas.

Reserves

Attractive reserve additions from our U.S. properties, oil sands and conventional Canadian operations were partially offset by unexpected capital inflation and negative revisions (mainly in the probable category) in our Canadian conventional areas. Enerplus achieved overall proved plus probable finding, development and acquisition costs including future development capital of $23.19/BOE in 2006 ($20.45/BOE excluding FDC) and a three-year average FD&A cost of $14.90/BOE ($11.51/BOE excluding FDC).

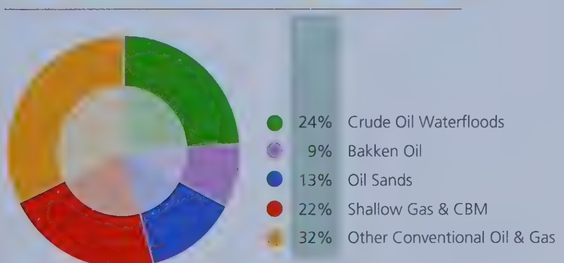
Other key points in our reserve assessment include:

- Reserve life index increased to 14 years in line with our historical performance.
- We replaced 82% of our produced reserves without the benefit of any significant acquisitions. Over the last five years, we have averaged almost 200% reserve replacement inclusive of acquisition and divestment activity.
- Our U.S. operations added 7.3 million BOE at a one-year proved plus probable F&D cost of $13.78/BOE including FDC reflecting a 20% increase in reserves at December 31, 2005 as a result of our strong operational and development performance in the U.S.
- 6.9 million BOE were added to our oil sands reserves at a one-year proved plus probable F&D cost of $10.54/BOE ($5.67/BOE excluding FDC) reflecting another successful year of core hole drilling and analysis.

- No changes were made to the allocation of reserves associated with the SAGD portion of the Joslyn lease versus the mining portion. Total and Enerplus are in discussions on a potential change to the lease development plan which could impact the reserve allocation between the mine and SAGD portions of the lease and the timing of reserve bookings.
- There are no proved or probable mining reserves included in our year-end reserve summary. The current North Mine project continues to progress and there is the potential to book probable reserves associated with this project at year-end 2007.
- Canadian conventional development added over 19 million BOE, excluding negative revisions, at a one-year proved plus probable F&D cost of $20.63/BOE ($17.17/BOE without FDC). This reflects the strong conventional drilling results we achieved in Canada which were partially offset by the negative revisions tied to existing Canadian operations.
- Proved and probable negative revisions of 7.5 MMBOE were predominantly from the "probable" reserves category which has less certainty than "proved" reserves. These revisions represent less than 2% of our total year-end reserves and were mainly due to performance and economic factors in a few of our older Canadian conventional properties.
- No changes to the after-tax calculations have been included for our Canadian assets in connection with the proposed changes on taxability for trusts in the Canadian market. Should the proposed legislation be enacted, Enerplus would provide an updated analysis which would include the effect of any enacted tax legislation.
- Acquisition and divestment activity resulted in no significant change to our reserves. Minor acquisitions were offset by the sale of a 1% working interest in our Joslyn lease.

For a full description of our reserves and the associated reserve reporting determination and methodologies, please see the reserve section starting on page 100.

Proved plus Probable Reserves by Resource Play



We replaced 82% of production from our internal development program without any significant acquisition activity.

Production Replacement

the energy
of **enerplus** is

our assets

bakken oil development

The Sleeping Giant oil project is located within the Williston Basin in Richland County in northeast Montana and produces light, sweet crude oil, associated gas and negligible water from the Middle Bakken formation.

As our single largest producing property, the Sleeping Giant project represents approximately 13% of our production and 9% of our proved plus probable reserves. During 2006 we invested $117 million to drill 41 gross wells (26.5 net) to add 7,800 BOE/day of incremental production at an attractive on-stream cost of $15,000/BOE/day. As part of our 2006 activities, we initiated an increased density drilling program by drilling 6 gross wells (4 net) at 3 wells per section. Based upon results to date, 10 additional increased density wells have been planned for 2007. Continued success may lead to additional increased density wells.

Enerplus has enjoyed tremendous development success since acquiring the property in two separate transactions in the latter part of 2005. To date, we have drilled 56 development wells with a 100% success rate and executed a successful re-fracture program resulting in production growth from 8,700 BOE/day upon acquisition to over 11,500 BOE/day at year-end 2006. These results are far better than we anticipated at the time of the acquisitions.

In 2007, we plan to invest $70 million to drill 26 gross (17 net) oil wells and re-fracture stimulate 12 gross (8 net) wells. This year's development activity will complete the second well per section program in the primary Bakken field area and focus on identifying and proving up new opportunities in the general area. We own 114,000 net acres of undeveloped land in Montana and North Dakota, portions of which we plan to test in 2007. The primary target on the undeveloped lands is the Bakken formation, however the lands are also prospective for the Ratcliffe, Mission Canyon, Birdbear, Duperow and Red River geological formations.

Key focus areas for us include:

- expanding the existing primary Bakken field boundaries including drilling a trendline Bakken exploration well on our lands in North Dakota and evaluating/testing the Glacier area northwest of our current primary field area
- proving up additional increased density drilling opportunities
- accelerating our successful re-fracturing program
- exploring the Bakken and other formations in Montana and North Dakota including completing a seismic program over a portion of our Montana lands with the intent to drill Red River exploration wells, and
- evaluating longer term potential which may include improved recovery via potential waterflood or gas injection.

Sleeping Giant is the single largest producing property in our portfolio.

41 MMBOE
proved plus probable reserves

8.6 year
reserve life index

280 million
barrels of original oil in place

26.5 net wells
drilled in 2006

11,300 BOE
average daily production

oil sands

Our oil sands business continues to be a significant part of our future growth. In addition to our activities on the non-operated Joslyn lease which includes both SAGD and mining potential, we made these additional advancements:

- Enerplus has built up an internal oil sands team with significant industry experience in SAGD development. We are actively pursuing an operated SAGD project in which to deploy this team.
- Our joint venture arrangement with Laricina Energy Ltd. ("Laricina") has been advanced. We invested approximately $3 million in 2006 to acquire a non-operated working interest in several land positions with SAGD development potential which will be operated by Laricina.

Joslyn Project

Enerplus and Total E&P Canada ("Total"), the operator of the Joslyn project, are continuing to review the lease development plans given the flexibility which exists for both SAGD and mining operations. Although meaningful progress was made in 2006, the complexities of determining the optimal development plan have extended the expected timeline. An extensive lease development plan is anticipated in 2007 and is not expected to impact current SAGD operations or the startup timing of the initial phase of the mine. The development plan will also provide an update of estimates relating to the future development capital associated with the mine development.

A summary of the expected production and timing for the various projects on the Joslyn lease are included in the table below. Not all dates are available given the uncertainty around the final full lease development plan.

Joslyn Project Development

	Project Production Throughput[1] (bbls/day)	Net Production Throughput (bbls/day)	Future Development Capital[2] ($millions)	Start Up[3]	Full Production[4]
Phase I & II SAGD	10,000	1,500	31	2006	2008
Phase III SAGD	15,000	2,250	284	TBD	TBD
North Mine	100,000	15,000	TBD	2013	2014
South Mine	100,000	15,000	TBD	2016	2017

(1) All production estimates are those of the Operator
(2) Future development capital for SAGD based on independent third party reserve report dated December 31, 2006. Future development capital for mining is currently under full review by the Operator as the project definition advances and new investment estimates are anticipated toward the end of 2007.
(3) Start up for SAGD refers to first steam. Start up for mining refers to initial extraction
(4) Full production refers to full project production throughput

Reserves

Independent reserves evaluation of the Joslyn lease indicates total proved reserves of 8.7 million BOE, and total proved plus probable reserves of 56.7 million BOE net to Enerplus in the SAGD area for Phases I - III. Independent contingent resource estimates for the North Mine indicate approximately 140 million BOE net to Enerplus, or over 900 million BOE gross. This is consistent with numbers filed in the North Mine regulatory application by the Operator. In addition, third party assessments estimate significant additional mining resources outside the North Mine area.

If current development plans are modified and a decision is made to mine some of the currently identified SAGD areas, existing SAGD Phase III probable reserve bookings could be impacted. Although mining typically provides about twice the recovery of the original bitumen in place versus SAGD projects, there could be timing differences between reserves bookings associated with the existing SAGD Phase III development plans versus possible expansion of mine development plans. Although timing of the expected booking may extend through 2007, depending on the progress made over the next year, we may be in a position to book probable reserves associated with the North Mine at year-end.

2006 Capital Investment

In regard to the Joslyn lease, spending in 2006 reached $36 million to advance both the SAGD ($33 million) and the mining options ($3 million). In addition, $3 million was spent to acquire lands in conjunction with Laricina, resulting in a total oil sands investment of $39 million in 2006. This capital included the drilling of close to 280 gross additional delineation wells over both SAGD and mining areas and the 4.5 gross sections of land acquired in late 2005. Capital investment to progress the SAGD development included the completion of central plant facilities, the commissioning and start-up of the water treatment system, the initiation of steam injection into SAGD well pairs, and the completion of a 40 kilometre pipeline from Joslyn to the Athabasca Terminal. Total continues to expect Phase II to reach peak production of 10,000 bbls/day gross (1,500 bbls/day net to Enerplus) in 2008, however due to reduced operating pressures, this may require additional wells and capital in 2007 and 2008. We currently do not have any production volumes associated with this project included in our 2007 production estimates as commercial volumes are not expected until 2008. Investment on the mining side supported the application for regulatory approval of the North Mine, representing 100,000 bbls/day of potential gross bitumen production.

2007 Capital Spending Outlook

Capital spending on oil sands is expected to increase to approximately $40 million including:

- Joslyn SAGD development of $21 million, which includes the continued start-up and ramp-up of Phase II well pairs, and the possible addition of 10 new well pairs late in the year. The regulatory approval process continues for SAGD Phase III with approvals expected in the first quarter of 2007 assuming no change in the base development plan. Currently Phase III represents a 15,000 bbl/day expansion of the existing facilities to a potential of 25,000 bbls/day of gross SAGD production (3,750 bbls/day net to Enerplus).
- Mining investment of $13 million to advance the regulatory approval process and engineering, and to further delineate the mine.
- Investment of $6 million to further delineate the new Laricina lands in the first quarter of 2007.

These investments will enhance the value of our portfolio of oil sands assets. Our capital spending may increase further should we identify and execute on other attractive oil sands opportunities.

Oil sands continues to be a significant part of our future.

56.7 MMBOE proved plus probable reserves

3,750 bbls/day SAGD potential

30,000 bbls/day mining potential

140 MMBOE potential reserves from the North Mine only

Large quantities of original oil in place offer significant future development potential.

104 MMBOE proved plus probable reserves

16.9 year reserve life index

over 1.4 billion barrels gross original oil in place

29.7 net wells drilled in 2006

17,400 BOE average daily production

crude oil waterfloods

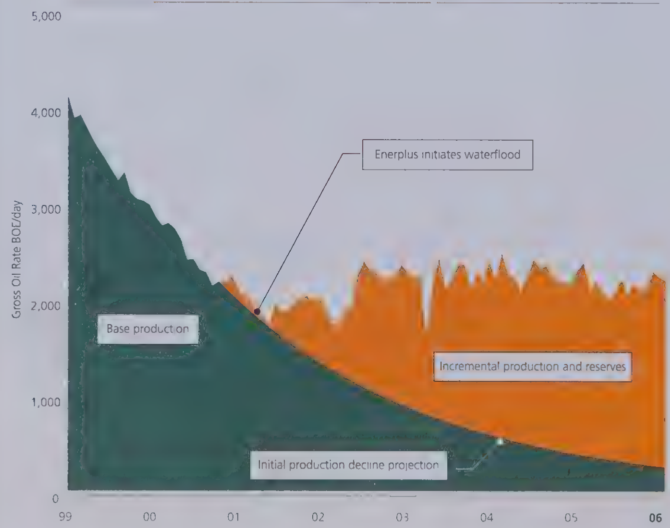
Crude oil waterfloods are a significant part of the Enerplus portfolio representing 20% of our production and 24% of our proved plus probable reserves. Waterfloods are an attractive asset because they typically have known accumulations of hydrocarbons with minimal geologic risk. Infill drilling and well/injector optimization are effective methods of enhancing recovery and creating value through the addition of production and reserves.

Enerplus has 12 major waterflood properties and numerous small waterflood properties with over 1.4 billion barrels of original oil in place. This represents a considerable resource for us as modest improvements in recovery factor can result in significant increases in reserves. During 2006 we invested approximately $66 million on waterflood development including drilling 40 gross (29.7 net) wells. Pembina and Joarcam were our most active waterflood development areas in 2006.

During 2007, we expect to maintain our investment activity in this area at approximately $65 million. This will include drilling 76 gross wells (41 net). Key development areas include Pembina, Joarcam, Virden as well as the Medicine Hat Glauconitic "C" East Unit. Although capital efficiency measures based on initial waterflood production may be higher, the low decline rates and long-life nature of these projects provide attractive full-cycle returns.

One of our major waterflood properties is our operated Medicine Hat Glauconitic "C" East Unit located in southeastern Alberta where we hold a high working interest. We purchased this property in 1999 when many in the industry did not believe it could be effectively waterflooded. We unitized the field, bought additional working interest, and successfully planned and implemented a waterflood which has significantly increased production and reserves. The field has 260 million BOE of OOIP and we have booked an expected recovery of 8% which leaves significant remaining oil in place. We continue to expand the waterflood area and look for further ways to enhance recovery.

Medicine Hat Glauc. 'C' Operated Oil Waterflood



shallow natural gas and coalbed methane

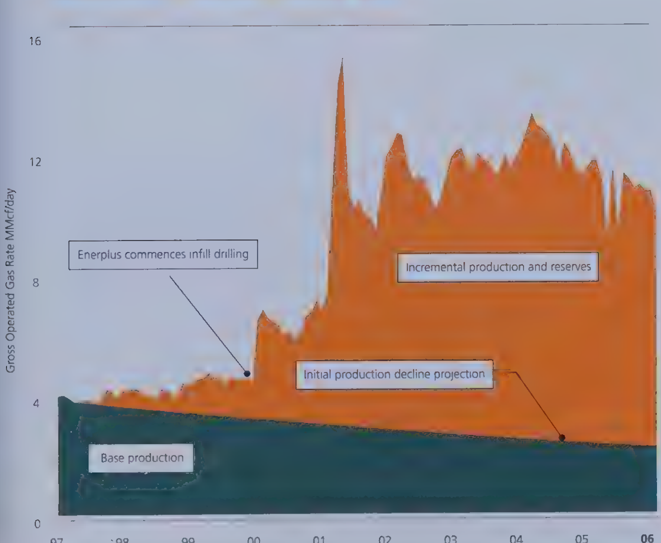
Shallow natural gas and coalbed methane are similar resource plays in that the key to success is the ability to execute large, multi-well development programs efficiently and to manage the post-drilling operations of these low pressure wells. The large aerial extent, low geologic risk and the repeatable, predictable, large-scale nature of shallow gas and coalbed methane make them bona-fide resource plays.

Shallow gas and coalbed methane represent 22% of our proved plus probable reserves, with an attractive reserve life index of 17.2 years. Production volumes from these two resource plays represent 16% of our total production, with shallow gas representing the majority in this category. During 2006, we invested $94 million on shallow gas/CBM development, drilling 430 gross (249.5 net) wells and adding 3,200 BOE/day of incremental production at an average on-stream cost of $29,400/BOE/day. Key areas of shallow gas development include Hanna, Bantry and Shackleton, while CBM development efforts were focused at Bashaw, Joffre and Trochu.

Currently, our inventory of shallow gas/CBM future drilling locations represents approximately six years of development at historical investment levels. However, for 2007 we have chosen to highgrade our development program to $43 million, focusing on our most profitable programs given potential risks in near-term gas prices. Should gas price strength continue, the size of this program could increase.

The following historical plot of our operated Medicine Hat shallow gas production is a typical example illustrating the long term success we have achieved through development of this resource. Since acquiring the property in 1997, we have drilled over 350 wells and increased production by 175% and reserves by 330%. Enerplus has also identified over 300 additional future drilling locations.

Medicine Hat Operated Shallow Gas



Enerplus is considered an industry leader in developing shallow natural gas.

98.0 MMBOE
proved plus probable reserves

17.2 year
reserve life index

1,900 net
future drilling locations

249.5 net wells
drilled in 2006

13,900 BOE
average daily production

Ownership in many play types reduces the risk associated with any one property.

144 MMBOE
proved plus probable reserves

9.6 year
reserve life index

$900 million
future development potential

43,200 BOE
average daily production

other conventional oil and gas

We also have a diversified portfolio of other conventional opportunities in western Canada. These properties are diversified by commodity (67% natural gas, 33% liquids) and are mixed between operated (46%) and non-operated (54%). Key opportunities include oil developments at Bantry North in southern Alberta and in southeast Saskatchewan while natural gas developments include the Deep Basin and Foothills areas of western Alberta and northeast British Columbia.

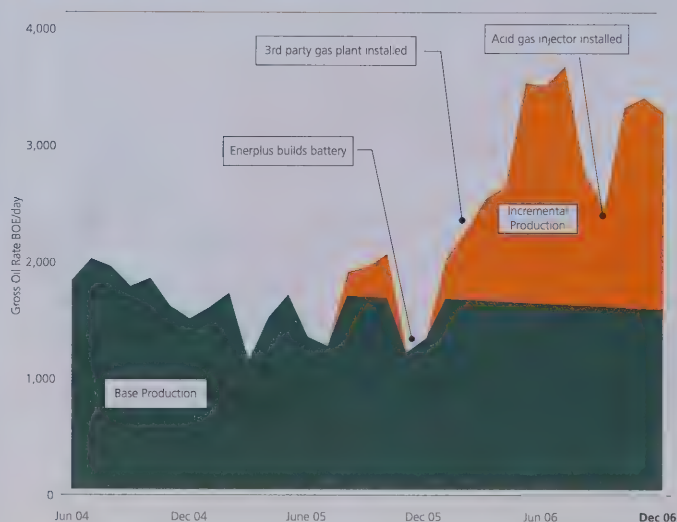
Conventional oil and gas represents approximately 51% of our production and 32% of our proved plus probable reserves. In 2006, we invested approximately $175 million in other conventional oil and gas development activities including the drilling of 275 gross wells (53.5 net).

In 2007, we plan to invest $192 million in development activities at other conventional oil and gas properties including drilling approximately 200 gross wells (70 net). Actual capital may vary depending on the activity levels from industry partners on non-operated properties in which we participate.

Enerplus targets the acquisition of properties with future development potential. The Bantry North property is a typical example of how we acquire underdeveloped properties and add significant value through full-scale development. Oil production at Bantry North is from the Sunburst formation and is pressure supported by a natural water drive. The following historical production plot illustrates the incremental production from infill drilling and well/facility optimization activities since Enerplus became operator.

Since acquiring a 100% working interest in the Bantry North oil property as part of the ChevronTexaco acquisition in mid-2004, we have drilled 11 wells and constructed production facilities which added up to 2,000 BOE/day of incremental production over and above natural production declines. The property represents a significant investment opportunity with OOIP of 51 million BOE and only 10.4% recovery to date. In 2006, we spent $8.3 million, drilling 3 more wells in the Sunburst zone along with investment in facilities and optimization activities. We have a similar budget planned for 2007 and expect to drill another 5 wells.

Bantry North Operated Oil Pool



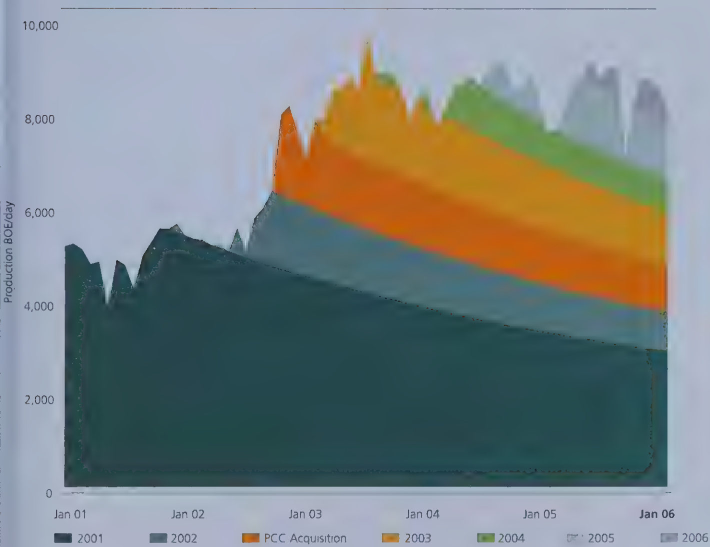
Southeast Saskatchewan

Our crude oil development program in southeast Saskatchewan continued in 2006. Key properties in this region include Tatagwa, Colgate, Heward, Neptune in southeast Saskatchewan and Routledge in Manitoba. Since we began developing this area in 2004, we have taken production from less than 800 BOE/day to approximately 1,800 BOE/day at year-end 2006. Rising crude oil prices and the application of horizontal drilling technology have supported the development work we've done in this area. During 2006, we invested \$29.8 million to drill 13 gross wells (11.9 net) and add 1,200 BOE/day of incremental production at an on-stream cost of \$24,800/BOE/day. In 2007, we expect to drill 29 gross oil wells (21.9 net) to further develop this region with a budget of \$38 million.

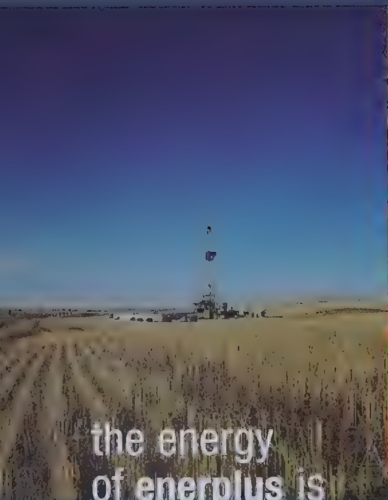
Deep Basin/Foothills

Development in the Deep Basin/Foothills typically involves the drilling of high impact, deep (up to 4,500 metres) natural gas wells. Given the expense of these wells, we have pursued a strategy of aligning ourselves with top-tier operators through small working interest positions that mitigate risk and leverage from external technical expertise. The following historical production plot illustrates how development activities have maintained production levels over natural production declines. During 2006 we invested \$34 million in the Deep Basin/Foothills, including the participation in 76 gross wells (6.0 net), to add 1,700 BOE/day of incremental production at an on-stream cost of \$20,000/BOE/day. In 2007 we expect to spend \$36 million to participate in the drilling of 88 gross gas wells (10 net).

Deep Basin Production Growth



Ownership in a variety of properties offers valuable insights across the industry.



the energy of **enerplus** is

our opportunity

acquisitions and divestments

2006 was a year our disciplined approach to acquisitions resulted in limited transactions despite actively pursuing numerous opportunities. As a result, we preserved our balance sheet and avoided the high cost acquisitions within Canada driven by an aggressive energy trust sector. Within the U.S. we tempered our activities as we built our U.S. operating group and executed an expanded internal development program which achieved strong internal production and reserve gains.

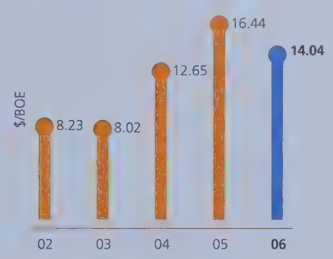
Given recent weakness in commodity markets and capital market uncertainty, we see an increasing number of attractive acquisitions at potentially more favourable pricing. This increased opportunity set comes at a time when our equity value is relatively stronger than the general trust sector, our balance sheet is strong and our U.S. execution capability is now in place.

During the year, through a series of small transactions, we increased our interests in core areas, notably at Sleeping Giant in Montana and at Gleneath in Saskatchewan. We acquired minor non-operated interests in a large block of land at Copton within the greater Deep Basin which has significant upside from relatively low risk drilling for deep, sweet natural gas. These properties were acquired at an attractive cost per BOE of $14 and a higher cost on a flowing barrel metric given the significant upside we see within the properties.

In early 2006, we sold a 1% working interest in our Joslyn oil sands lease in exchange for an equity stake in Laricina Energy Ltd. a private oil sands focused company. Given the low selling price of these reserves and the modest number of acquired reserves for the year, the resulting net acquisition metrics appear unattractive. However, the chart below offers more comparable per BOE and per flowing BOE metrics by excluding the Joslyn sale.

A disciplined approach to acquisitions resulted in favourable costs on a BOE basis.

Acquisition Cost per BOE



2006 Acquisition & Divestment Summary

	Cost/ Proceeds* ($ millions)	Proved plus Probable Reserves (MBOE)	Production (BOE/day)	Cost of Proved plus Probable Reserves ($/BOE)	Cost per Daily BOE
Acquired	$ 51.3	3,654	655	$ 14.04	$78,321
Divested**	(1.4)	(63)	(26)	(22.22)	53,846
Net excluding Joslyn	$ 49.9	3,591	629	$ 13.90	$79,332
Joslyn Divestment	(19.7)	(3,329)	n/a	(5.91)	n/a
Net including Joslyn	$ 30.2	262	629	$ 115.27	$48,013

* After adjustments for working capital and excluding future development capital
** Excludes sale of reserves of Joslyn for equity stake in Laricina

Our equity investment strategy provides us with a number of strategic benefits.

Acquisition of Gross Overriding Royalty Interests

On January 31, 2007, Enerplus acquired various gross overriding royalty ("GORR") interests in the state of Wyoming for total consideration of US$52 million (CDN$60 million). This acquisition represents a modest addition to our assets in the United States and establishes a new area with significant gas development potential.

The assets produce natural gas from the EnCana Corporation operated Jonah gas field in Wyoming, which is one of the largest gas fields in the U.S. with an estimated original gas in place of 14 trillion cubic feet. We have acquired approximately 540 BOE/day of daily production and approximately 2.2 million BOE of proved reserves and 2.9 million BOE of proved plus probable reserves. This represents a GORR of about 0.5% on approximately 650 producing gas wells. The proved plus probable reserve life index of the assets is 15.9 years, calculated using independent third party engineering reserve estimates and management's estimate of current production. We believe the field has a significant number of additional infill drilling locations that will provide growth potential for the future. Enerplus will not be required to expend any future development capital on the assets. We expect the net operating cash flow per BOE, net of all applicable U.S. taxes, to be significantly higher than that of our existing production due to the nature of the GORR which is not subject to deductions for operating costs and royalties.

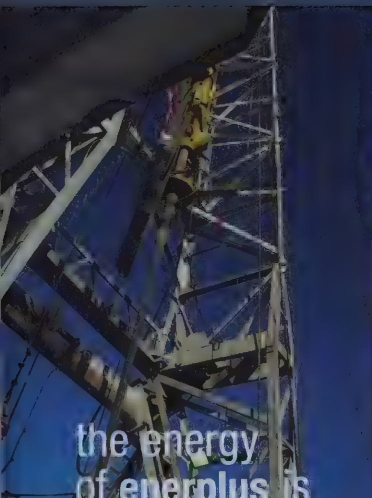
Equity Investment Strategy

During the year, we continued to make strategic equity investments in select junior exploration and production and infrastructure companies with experienced management teams. The relationships provide us one or more of the following strategic drivers: insight into attractive developing plays and technologies, advantages on future acquisitions, potential increased future deal flow, and/or enhanced monetization of non-core assets. To date we have enjoyed success in all our prior equity investments as highlighted below.

Security	Investment date	Original Investment ($MM)	Sale Price ($MM)	Realized Gain ($MM)	Strategic Driver
Ice Energy*	July 2003	$7.3	$16.6	$9.3	CBM, potential acquisition
Galleon Energy	Sept 2003	0.1	0.8	0.7	Potential joint ventures
StarPoint Energy	Sept 2003	0.2	1.0	0.8	Potential joint acquisitions
Mission Oil & Gas	Jan 2005	2.3	16.0	13.7	Bakken, potential corporate acquisition
Argo Energy	Dec 2003	4.4	7.0	2.6	Potential joint acquisitions
Total		**$14.3**	**$41.4**	**$27.1**	

* Enerplus purchased Ice Energy in a competitive transaction in January 2004

We have other investments including two new international equity investments, a new infrastructure investment and other investments which total approximately $50 million of initial capital. In lieu of spending significant capital to learn whether international opportunities fit our business model, we have chosen to use our equity investment strategy as a first step.



the energy
of enerplus is

our responsibility

corporate governance

In its simplest form, corporate governance is the set of rules the board of directors and management observe when governing an organization. The principles of strong corporate governance can define an organization's integrity. At Enerplus, we take pride in observing industry's corporate governance best practices. For complete information on our corporate governance practices, please read our 2007 Information Circular and Proxy Statement.

Below is a listing of some of our corporate governance practices:

Corporate Governance Checklist

√	Enerplus' Board of Directors is composed of nine members, eight of whom are considered independent. The CEO is the only member of the Board who is non-independent.
√	The Chairman of the Board is an independent director.
√	Only independent directors serve on committees of the Board.
√	Position descriptions are in place for the Chairman of the Board, the chair of each Board committee and of the CEO.
√	The Corporate Governance & Nominating Committee is responsible for and has implemented procedures for the orientation and education of Board members. These procedures assist in defining a new director's role and responsibilities while serving as a director and for ensuring the continued development of existing Board members.
√	Committees of the Board, and the Board itself, operate in accordance with a charter and work plan outlining their respective duties and responsibilities.
√	Together with management, the Board attends an annual strategic session to review, amend or adopt long-term strategies and new corporate objectives for Enerplus for the upcoming year.
√	The Board of Directors is responsible for the overall stewardship of the Fund.
√	The Corporate Governance & Nominating Committee reviews any potential issues of conflict of interest relating to Board members serving on other boards as they arise.
√	The Board ensures policies and processes are in place for the identification of principal business risks and reviews and approves risk management strategies.
√	The Corporate Governance & Nominating Committee annually reviews and makes recommendation to the Board regarding director remuneration.
√	The Board of Directors is elected annually by the Fund's unitholders.
√	The CEO shall offer to resign from the Board upon the resignation, removal or retirement as an officer of the Fund. The Corporate Governance & Nominating Committee has discretion as to whether or not it should accept such tendered Board resignation.
√	The Corporate Governance & Nominating Committee of the Board annually reviews each director's past performance to determine that director's suitability for continuation on the Board. Board members are annually assessed by their peers with respect to their effectiveness and contribution.
√	Each scheduled Board and committee meeting is followed by an in-camera discussion of the independent directors without the presence of management or the CEO, who is a non-independent director.
√	Directors must advise the chairman of the Corporate Governance & Nominating Committee before accepting an invitation to serve on the board of another public company.
√	The Board annually reviews employee and director compliance with Enerplus' code of business conduct policy.
√	When describing compensation policies and disclosing compensation awarded to directors, the CEO and named executives, Enerplus exceeds the legally required standards and endeavours to disclose this information in a fulsome and transparent manner in its annual corporate disclosure documentation.

- √ Committee assignments and the designation of committee chairs are determined by the Corporate Governance & Nominating Committee based on each director's knowledge, interests and areas of expertise.
- √ The Board favours rotation of committee assignments and chairs, where practicable, to broaden the exposure of individual directors and introduce new perspectives to the Board committees.
- √ During their tenure, each of the directors is required to maintain ownership of a minimum of 3,000 of the Fund's trust units within five years of their nomination to the Board.
- √ The Board no longer participates in any type of stock option plan of the Fund.
- √ No person shall be nominated by the Board to serve as a director after he or she has passed his or her 75th birthday, unless the Corporate Governance & Nominating Committee has voted, on an annual basis, to waive or continue to waive, the mandatory retirement age of such person as a director.
- √ Executives are obligated to maintain a minimum ownership in Enerplus trust units. The President and CEO is required to maintain three times his salary in trust units, while other executives are required to hold two times or one times their salary in trust units, depending on their seniority.
- √ The Fund has designated periods in which the trading of the Fund's securities is prohibited by directors, officers and employees.

environment, health and safety

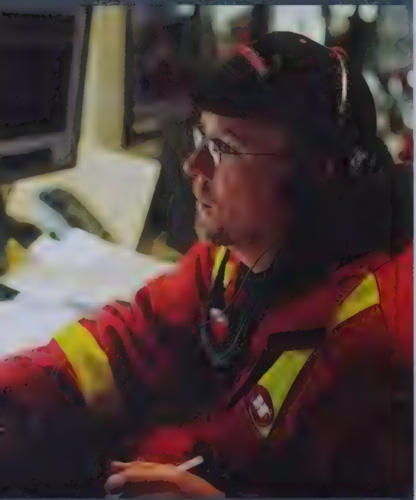
Enerplus places a high priority on preserving the quality of our environment and protecting the health and safety of our employees, contractors and the public in the communities in which we live and work. We actively participate in industry-recognized programs at the highest possible levels in an effort to support continuous improvement.

Enerplus has once again received the Certificate of Recognition as part of the Partnership Program with Alberta Human Resources and the Workers' Compensation Board. This certificate is given to employers who develop health and safety management systems that meet established standards. We have maintained our COR through annual reviews and audits every three years since 2000. The second independent audit of our EHS management system was conducted in 2006 and received an impressive 95% score.

Our safety performance unfortunately declined in 2006. A total of eight employee recordable injury incidents were recorded this year, resulting in a lost time injury frequency rate of 0.53 per 200,000 man hours compared to 0 incidents per 200,000 man hours in 2005. In addition, our contractor lost-time injury frequency also increased from 0.46 per 200,000 man hours in 2005 to a rate of 0.97 per 200,000 man hours this year. While the majority of these incidents were of a lesser severity, we are nevertheless concerned about the higher level of incidents. We are working to improve our safety performance through increased awareness in the field, personalizing safety messages so they have a more profound impact on personal decisions, and increasing the accountability for safety throughout the organization.

Enerplus is committed to meeting our responsibilities to protect the environment through a variety of programs and actively monitoring our compliance with all regulators. We engage in the following activities:

- Participated in the Environment, Health and Safety Stewardship Program developed by the Canadian Association of Petroleum Producers at the highest level, platinum. Our participation requires our commitment to continuous improvement in our EHS management practices including sound planning and implementation, open communication and demonstrated performance, and a thorough external audit of our activities at least once every five years.
- Increased our spending on reclamation and site abandonment by 48% to $6.1 million. Site abandonment and reclamation occurs when areas are returned to their original site once operations have been completed. Our reclamation activities saw 36 reclamation certificates received with another 58 sites ready for review by Alberta Environment. This correlates to a 13% reduction in our total reclamation sites from 2005.



We continually look for ways to improve our environment, health and safety stewardship.

- Doubled our remediation spending in 2006 to $9.6 million and reduced our reportable spills by 18%. Remediation is the environmental clean-up of spills or issues, many of which are associated with older properties or changing regulations.
- Enhanced our pipeline integrity efforts and reduced pipeline failures by 13% year-over-year through our Pipeline Management Program and related activities. The Pipeline Management Program is designed to maintain the integrity of our underground pipelines through on-going risk assessment. In 2006, 90% of our 6,000 kilometres of pipeline were assessed with appropriate actions taken to identify future pipeline leaks or breaks.
- Increased the number of emergency response drills within Enerplus to prepare our staff in the case of an emergency.

Our 2007 activities and initiatives in the area of EHS include:

- Maintaining spending levels on abandonment and restoration activities
- Working to improve our safety performance through awareness in the field, personalizing safety messages so they have a more profound impact on personal decisions and increasing the accountability throughout our organization for safety.
- Evaluating our impact on the environment. With growing concern over global warming and modern man's impact on the environment, we are looking at additional ways we can minimize our footprint on the world.
- Evaluating and implementing options to increase safety presence and ownership of our safety programs at the field level.
- Expanding our efforts relating to employee and contractor safety compliance through enhanced safety orientations, awareness and training sessions.

Overall, we believe our environment, health and safety initiatives confirm our ongoing commitment to environmental stewardship and the health and safety of our employees, contractors and the general public in the communities in which we operate.

community investment

We believe community involvement helps us build and strengthen relationships to achieve healthy, sustainable communities in which to live and work. Over the past 21 years, we have participated in fundraising campaigns, volunteer activities, event sponsorships, and created significant long-term partnerships with various national organizations and local charities. During 2006, we invested over $1.6 million and hundreds of man hours with various organizations throughout our areas of operation. Our efforts are focused in four key areas – health and research, education, environment, health and safety, and community living.

In 2006, Enerplus established three new long-term partnerships within our focus areas. The first and largest was the establishment of a partnership with SAIT Polytechnic to create the Enerplus Innovation Centre, a new centre in the Trades and Technology Complex that will specialize in applied research and innovation. One of the greatest challenges we face in the energy industry is a shortage of skilled personnel and we believe it is our responsibility to work to find solutions to this issue. We have made a commitment of $5 million, payable

over five years, toward the development of this Centre which is expected to be completed by the spring of 2009. We believe this commitment will help alleviate a shortage of skilled personnel in the energy industry as well as advance applied research and innovation in a variety of industries inclusive of energy.

In the area of Health and Research, we continued our support in two ways of the new Alberta Children's Hospital, which opened in September of this year. First, we renewed our long-term commitment by providing $150,000 payable over a further five-year period. Secondly, as part of our 20th anniversary celebration, we held the "Legends of the Oil Patch Texas Hold 'Em Charity Poker Tournament", raising $158,700 for the new hospital. This event was so successful, we plan to make it an annual fundraiser.

Our third partnership is in the area of cancer research. In 2006, Enerplus became the first organization in Canada to fund a specific research program through a five-year $125,000 donation to the Canadian Cancer Society. Our donation will provide funding for the research work of Dr. Michael Hendzel on the causes of cancer and how to more effectively treat the disease. We continue to support the treatment of cancer through contributions to the Tom Baker Cancer Centre and the Alberta Cancer Foundation.

The health and safety of our employees and the care of our environment remain key concerns for Enerplus. In 2006 we increased our support for the Alberta Eco Trust Foundation, a group that provides environmental educational programs to schools and communities throughout the province. Over the last two years we have also supported Ducks Unlimited, STARS Air Ambulance and participated in Energy in Action, a Canadian Association of Petroleum Producers initiative focused on stewardship. The program teaches youth about natural resources and encourages students to become good environmental stewards through both classroom instruction and hands-on activities. Enerplus led the program in Bashaw, Alberta where 12 employees from four local oil and gas companies joined 29 students to plant more than 25 trees on the school grounds.

Enerplus regards our support of community programs as a way to help build strong communities which benefit all our staff and their friends and families. The Enerplus United Way campaign was a great success in 2006 with over $330,000 raised by employees throughout the company, field and office, including corporate matching funds of $150,000. This year, our Red Deer office donated $51,852 to the Central Alberta United Way an increase of 58% since 2003. As a result of our exceptional level of support, the United Way of Central Alberta presented Enerplus with the 2006 Community Builder award.

2006 was also our fifth year supporting Habitat for Humanity. With our partners CIBC World Markets and Nexen Inc., our employees helped to build our fifth house in Calgary. In addition, our employees in Denver volunteered their time and energy to help build a new home in their community.

Through volunteer involvement and contributions to non-profit and community-based organizations we are helping to improve the communities in our areas of operation. In 2007, we will continue to embrace these responsibilities.

Building strong communities benefits our staff, friends and families.

the energy
of **enerplus** is

our performance

management's discussion and analysis ("MD&A")

The following discussion and analysis of financial results is dated February 21, 2007 and is to be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2006 and 2005. All amounts are stated in Canadian dollars unless otherwise specified. All references to GAAP refer to Canadian generally accepted accounting principles. All note references relate to the notes included with the consolidated financial statements. In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of crown and other royalties, unless otherwise stated. Oil and natural gas reserves and production are presented on a company interest basis which is not a term defined or recognized under NI 51-101. Therefore, our company interest reserves may not be comparable to similar measures presented by other issuers. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. Certain prior year amounts have been restated to reflect current year presentation.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our disclaimer on forward-looking statements.

In 2006, cash flow, net income and cash distributions to unitholders increased.

Non-GAAP Measures

Historically we used the non-GAAP measure funds flow from operations (or "funds flow") to analyze operating performance, leverage and liquidity. We are now utilizing the GAAP measure cash flow from operating activities ("cash flow") instead of funds flow. The difference is that cash flow from operating activities includes changes in non-cash working capital and appears on our Consolidated Statements of Cash Flows.

We also historically used the non-GAAP measure cash available for distribution. We are now using cash distributions to unitholders ("cash distributions") which also appears on our Consolidated Statements of Cash Flows. Cash available for distribution was based on the twelve month production period January through December wherein the related distributions were paid with a two month lag or March through February respectively. Cash distributions include amounts paid or declared during the calendar year which relate to the twelve month production period December through November wherein the related distributions are paid February through January.

Our payout ratio was previously calculated as cash distributions divided by funds flow; however, as a result of the above-mentioned changes, our payout ratio is now calculated as cash distributions divided by cash flow from operating activities. This reflects the proportion of cash flow paid out to investors and not reinvested in the business. The term payout ratio does not have a standardized meaning as prescribed by GAAP and therefore may not be comparable with the calculation of a similar measure by other entities.

Refer to the Liquidity and Capital Resources section of the MD&A for further information on cash flow, cash distributions and payout ratio.

Update on Canadian Government Announcement on Intention to Tax Trusts

On October 31, 2006, the Canadian federal government (the "Government") announced plans to introduce a tax on publicly traded income trusts. For existing income trusts, such as Enerplus, the new tax measures would be effective for 2011, provided we comply with the "normal growth" parameters regarding equity growth until that time. A "Notice of Ways and Means Motion" was passed in Parliament shortly after the Government announcement. This notice was a one-page summary of the Government's proposal and it did not identify any specific amendments to the Income Tax Act.

On December 15, 2006 the Government announced safe harbour guidance regarding "normal growth" for equity capital. The safe harbour amount will be measured by reference to the individual trust's market capitalization as of the end of trading on October 31, 2006 (which was approximately $7.5 billion for Enerplus). For the period from November 1, 2006 to December 31, 2007 a trust's safe harbour amount will be 40 percent of the October 31, 2006 market capitalization benchmark and for each of the years 2008 through and including 2010 will be 20 percent of the benchmark, cumulatively allowing growth of up to 100 percent until 2011. In addition, we understand that trusts will be able to issue equity to retire debt existing on October 31, 2006 without eroding their safe harbour limits.

On December 21, 2006, the government released more detailed draft legislation with respect to the proposed amendments to the Income Tax Act and requested comments from stakeholders. In late January 2007, the House of Commons Standing Committee on Finance held special hearings on the proposed tax and the draft legislation. At this time we are unable to determine the impact, if any, these hearings may have on the proposed legislation or the timing of when the proposed legislation could be passed in Parliament.

Should the tax legislation become substantially enacted, future income taxes may be adjusted to include temporary differences between the accounting and tax bases of the trust's assets and liabilities. In addition, reserves reported under NI 51-101 may be adjusted to include an estimate of the tax effect on our estimated future revenues from our reserves. We will assess alternative organizational structures during the four-year transition period. We are confident we have the team, the assets, and the opportunities to prosper regardless of our organizational structure.

2006 Overview

During 2006 we executed our largest capital program to date, spending $491.2 million. The increased capital spending resulted in average production of 85,779 BOE/day, exceeding our guidance of 85,500 BOE/day. Both general and administrative costs ("G&A") and operating costs were higher than guidance due to cost escalation associated with the high level of industry activity.

Compared to 2005, cash flow increased 11% to $863.7 million, net income increased 26% to $544.8 million, and cash distributions increased 23% to $614.3 million. Increased production, crude oil prices and lower risk management costs were partially offset by reduced natural gas prices and increased costs, resulting in the year-over-year increases in cash flow and net income. Monthly cash distributions remained constant at $0.42 per trust unit throughout 2006.

Our trust unit price declined in the last quarter of 2006 due to the Government's proposed tax on income trusts and, to a lesser extent, in response to weakening crude oil and natural gas prices. Our Canadian unitholders realized a negative 0.3% total return while our U.S. unitholders realized a 0.1% total return in 2006 (representing the change in unit price plus distributions paid during the year).

Highlights

- Cash flow increased 11% to $863.7 million from $774.6 million in the previous year.
- Cash distributions increased in 2006 by 23% to $614.3 million or 11% per unit to $5.05 per unit (based on weighted average trust units outstanding) compared to 2005.
- Actual monthly distributions per trust unit remained constant throughout 2006 at $0.42 resulting in annual cash distributions of $5.04 for each unitholder.
- Average selling price per BOE decreased 4% to $50.23 due to weaker natural gas prices.
- Our largest development capital program to date of $491.2 million was essentially in line with our target of $485.0 million.
- The additional development capital spending during 2006 resulted in production that averaged 85,779 BOE/day exceeding our annual target of 85,500 BOE/day.
- Net income increased 26% to $544.8 million. On a trust unit basis this resulted in an increase of 13% to $4.48 per unit reflecting the increase in trust units outstanding.
- Our payout ratio increased to 71% from 64% in 2005 as we distributed more of our cash flow from operating activities to our unitholders.
- Operating costs were $8.02/BOE in 2006, 8% higher than $7.45/BOE in 2005.
- G&A costs were $1.91/BOE, higher than our guidance of $1.85/BOE and 37% higher than $1.39/BOE in 2005.
- Our realized commodity price risk management cash costs were $34.3 million ($1.10/BOE) during 2006, a 76% reduction compared to $142.6 million ($4.90/BOE) during 2005.
- Drilling efforts resulted in a success rate of over 99% with participation in 361 net wells.
- Our finding, development and acquisition costs ("FD&A") for the year were $23.19/BOE on a proved plus probable basis and $28.82/BOE on a proved basis.
- Proved plus probable reserves decreased 1% to 443.3 MMBOE and proved reserves decreased 4% to 299.8 MMBOE.
- Reserve additions from development capital spending and acquisitions replaced 82% of 2006 production on a proved plus probable basis and 57% of production on a proved basis.
- Our Reserve Life Index ("RLI") continued to be one of the longest in the sector at 14.0 years on a proved plus probable basis and 10.1 years on a proved basis, including both conventional and non-conventional reserves.
- Our recycle ratio (operating income divided by FD&A) was 1.6x on a three-year basis and 1.4x for 2006 using proved plus probable reserves.
- We continue to maintain a conservative balance sheet as evidenced by a net debt to trailing 12 month cash flow ratio of 0.8x.

Results of Operations

Production

Daily production during 2006 averaged 85,779 BOE/day, slightly above our guidance of 85,500 BOE/day and 8% higher than 79,727 BOE/day in 2005. The increase was primarily due to our U.S. acquisitions in the second half of 2005 which added an incremental 8,121 BOE/day of production in 2006 along with our development capital program which added an additional 5,633 BOE/day of production in 2006. These increases were offset in part by natural reservoir declines experienced throughout the year.

Average production during the year was weighted 53% to natural gas and 47% to liquids on a BOE basis. Average production volumes for the years ended December 31, 2006 and 2005 are outlined below:

Daily Production Volumes	2006	2005	% Change
Natural gas (Mcf/day)	270,972	274,336	(1%)
Crude oil (bbls/day)	36,134	29,315	23%
Natural gas liquids (bbls/day)	4,483	4,689	(4%)
Total daily sales (BOE/day)	85,779	79,727	8%

We exited the year with production of approximately 87,500 BOE/day based on December's production, in line with our target of 88,000 BOE/day.

We expect 2007 annual production volumes to remain essentially flat year-over-year, averaging 85,000 BOE/day, weighted 54% to natural gas and 46% to liquids. As a result of the timing of our planned development capital program, we expect to exit 2007 with production of approximately 86,000 BOE/day. This does not contemplate any potential acquisitions or dispositions.

Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, cash flow and financial condition. The following table compares our average selling prices for 2006 with those of 2005. It also compares the benchmark price indices for the same periods.

Average Selling Price[1]	2006	2005	% Change
Natural gas (per Mcf)	$ 6.81	$ 8.41	(19%)
Crude oil (per bbl)	61.80	55.93	10%
Natural gas liquids (per bbl)	50.90	47.33	8%
Per BOE	$50.23	$52.36	(4%)

[1] Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

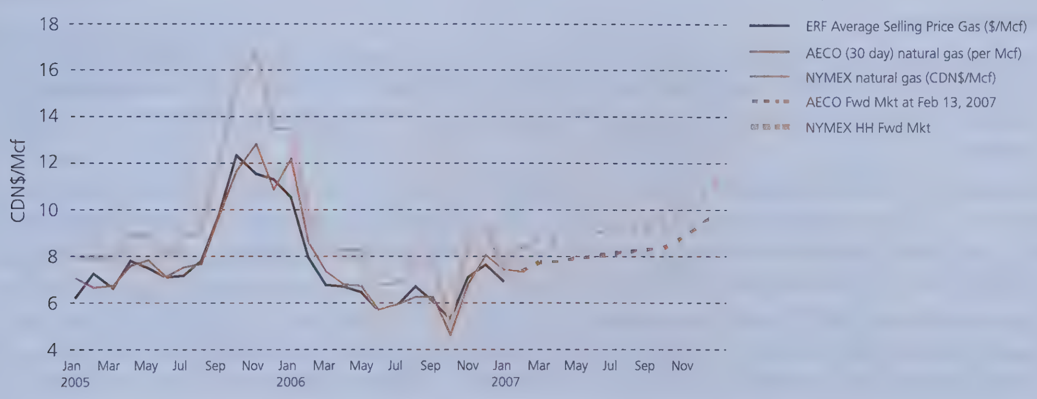
Average Benchmark Pricing	2006	2005	% Change
AECO natural gas – monthly index (CDN$/Mcf)	$ 6.99	$ 8.48	(18%)
AECO natural gas – daily index (CDN$/Mcf)	6.53	8.71	(25%)
NYMEX natural gas – monthly NX3 index (US$/Mcf)	7.26	8.55	(15%)
NYMEX natural gas – monthly NX3 index: CDN$ equivalent (CDN$/Mcf)	8.25	10.30	(20%)
WTI crude oil (US$/bbl)	66.22	56.56	17%
WTI crude oil: CDN$ equivalent (CDN$/bbl)	75.25	68.14	10%
US$/CDN$ exchange rate	$ 0.88	$ 0.83	6%

Natural Gas

Natural gas prices were in a downward trend during 2006, influenced initially by demand loss, the residual high storage inventories after a warm winter, and strong drilling. In July 2006, prices received some support due to above normal temperatures in key consuming regions of the United States, and forecasts for a strong hurricane season. Year-over-year the natural gas storage surplus continued to build and those hurricanes that did develop were moderate. This ultimately drove the AECO monthly index price to a low for the year of $4.45/Mcf in October, with the daily spot price dropping to $3.25/Mcf in the same month. Spot and forward prices recovered significantly as winter approached, with spot prices rising briefly above $8.00/Mcf before the warmer than normal November and December, caused by an El Nino weather pattern, pushed the daily spot price back to $6.07/Mcf on December 31, 2006.

Our natural gas portfolio is comprised of aggregator, AECO, and downstream direct sales. In 2006 we sold 42% of our natural gas on the daily AECO market and 42% on the monthly AECO market, as well as 16% against the day and month NYMEX indices. During 2006 we realized an average price for our natural gas sales of $6.81/Mcf (net of transportation costs), a decrease of 19% from the $8.41/Mcf realized in 2005. This reduction is comparable to the price decreases realized in each of: the AECO daily index which decreased by 25% year-over-year; the AECO monthly index which decreased by 18%; and the NYMEX monthly index (converted to CDN$/Mcf) which decreased by 20%.

Natural Gas Prices

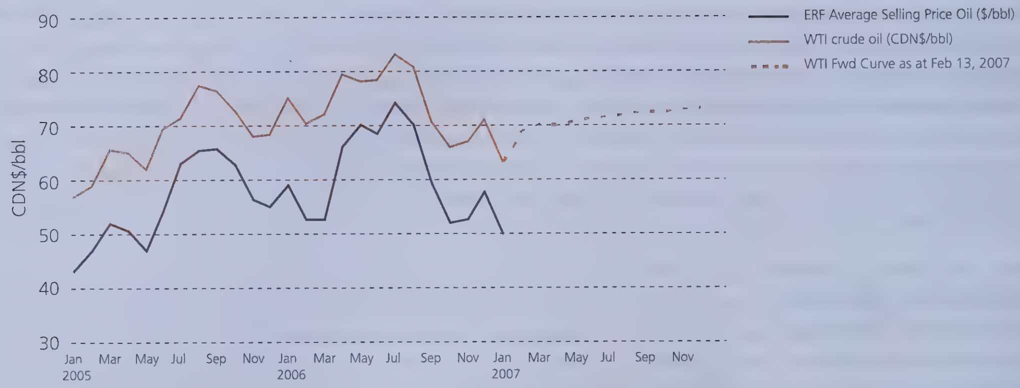


Crude Oil

World crude prices continued to be influenced by a tight supply-demand balance through the first half of 2006, continuing the upward trend in prices experienced during 2005. WTI spot prices peaked in July during the Israel-Hezbollah conflict at US$77.03/bbl. With strong inventories, forecasts for warmer than normal conditions for the winter, and a strengthening supply picture, prices fell thereafter through the second half of 2006. The WTI spot price hit a low of US$55.81/bbl in November, representing a 28% reduction from the July high.

Our crude oil portfolio in 2006 was approximately 70% light/medium and 30% heavy. The average price received for our crude oil (net of transportation costs) was $61.80/bbl during 2006, a 10% increase over 2005. Similarly, the West Texas Intermediate ("WTI") crude oil benchmark price, after adjusting for the change in the US$ exchange rate, also increased by 10% year-over-year. Although we added more light sweet crude oil to our portfolio in 2006 compared to 2005, this benefit was offset by widening heavy crude oil differentials during the year.

Crude Oil Prices



The Canadian dollar strengthened 6% against the U.S. dollar during 2006 compared to 2005 based on the annual average exchange rate. As most of our crude oil and a portion of our natural gas are priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate reduced the Canadian dollar prices that we would have otherwise realized.

Price Risk Management

While the overall energy outlook remains generally bullish long term, there remains uncertainty as to the direction prices might move in 2007. Both natural gas and crude oil prices have the potential to fall further in 2007 given current levels of inventory, aggressive drilling in the U.S. for gas and across the globe for crude oil and some uncertainty with respect to the world economy.

We have developed a price risk management framework to respond to the volatile price environment in a prudent manner. Consideration is given to our overall financial position together with the economics of our acquisitions and capital development program. Consideration is also given to the upfront costs of our risk management program as we seek to limit our exposure to price downturns while maintaining participation should commodity prices increase.

Given our price risk management framework we have entered into additional commodity contracts during the fourth quarter and subsequent to year-end. These contracts are designed to protect a portion of our natural gas revenue for the period January 2007 through March 2008 and to protect a portion of our crude oil revenue for the period January 2007 through December 2007. We have also hedged electricity volumes for the period January 2007 through September 2008 to protect against rising electricity costs in the Alberta power market. See Note 10 for a detailed list of our current price risk management positions.

The following is a summary of the physical and financial contracts in place at February 13, 2007 as a percentage of our forecasted net production volumes:

	Natural Gas (CDN$/Mcf)			Crude Oil (US$/bbl)
	January 1, 2007 – March 31, 2007	April 1, 2007 – October 31, 2007	November 1, 2007 – March 31, 2008	January 1, 2007 – December 31, 2007
Floor Protection Price	$ 7.53	$7.32	$ 8.13	$68.93
% (net of royalties)	21%	32%	3%	34%
Upside Capped Price	$10.64	$9.07	$10.31	$ –
% (net of royalties)	14%	28%	3%	– %
Fixed Price	$ –	$7.58	$ 8.70	$66.24
% (net of royalties)	– %	12%	2%	8%

Based on weighted average price, before premiums, and average production of 85,000 BOE/day.
Assumes production mix of 54% gas, 42% oil and 4% NGL.

Accounting for Price Risk Management

During 2006, our commodity price risk management positions incurred cash costs of $27.2 million on crude oil contracts and $7.1 million on natural gas contracts compared to cash costs of $91.0 million and $51.6 million respectively during 2005. The decrease in crude oil cash costs is due to the expiration of contracts on June 30, 2006 that had ceiling prices between US$35.35/bbl and US$45.80/bbl on 4,500 bbls/day. The decrease in natural gas cash costs is the result of lower natural gas prices experienced during 2006 and the expiration of old contracts.

The unrealized gain on our financial contracts of $81.0 million for the year ended December 31, 2006 represents the change in the fair value of financial contracts since December 31, 2005. As the forward markets for natural gas and crude oil fluctuate, and new contracts are executed and existing contracts are realized, changes in fair value are reflected as a non-cash charge or increase to earnings. At December 31, 2006 the fair value of our financial contracts net of premiums is $23.6 million and is recorded on the balance sheet as a deferred financial asset. See Note 2 for details.

Effective December 31, 2005, we elected to stop designating our commodity financial contracts as hedges. As a result we recorded a deferred credit representing the fair value of these contracts on that day, with an offset recorded as a deferred financial asset that is amortized to income over the life of the underlying contracts. These costs of $49.9 million are fully amortized at December 31, 2006. See Note 2 for details.

The following table summarizes the effects of our financial contracts on income for the years ended December 31, 2006 and 2005.

Risk Management (Gains)/Losses

($ millions, except per unit amounts)	2006		2005	
Cash (gains)/losses:				
Crude oil	$ 27.2	$ 2.06/bbl	$ 91.0	$ 8.51/bbl
Natural Gas	7.1	$ 0.07/Mcf	51.6	$ 0.52/Mcf
Total Cash losses	$ 34.3	$ 1.10/BOE	$142.6	$ 4.90/BOE
Non-cash (gains)/losses:				
Change in fair value – financial contracts	$(81.0)	$(2.59)/BOE	$ (35.8)	$(1.23)/BOE
Amortization of deferred financial assets	49.9	$ 1.59/BOE	3.1	$ 0.11/BOE
Total Non-cash gains	$(31.1)	$(0.99)/BOE	$ (32.7)	$(1.12)/BOE
Total losses	$ 3.2	$ 0.11/BOE	$109.9	$ 3.78/BOE

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts as described in Note 10 and are based on current forward markets for 2007 at February 13, 2007. To the extent the market price of crude oil and natural gas change significantly from current levels, the sensitivities will no longer be relevant as the effect of our commodity contracts will change.

Sensitivity Table	Estimated Effect on 2007 Cash Flow per Trust Unit(1)
Change of $0.15 per Mcf in the price of AECO natural gas	$0.08
Change of US$1.00 per barrel in the price of WTI crude oil	$0.05
Change of 1,000 BOE/day in production	$0.13
Change of $0.01 in the US$/CDN$ exchange rate	$0.12
Change of 1% in interest rate	$0.06

(1) Assumes constant working capital and 123,151,000 units outstanding.

The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors.

Revenues

Crude oil and natural gas revenues for the year ended December 31, 2006 were $1,572.7 million ($1,595.3 million, net of $22.6 million of transportation costs) compared to $1,523.7 million ($1,550.6 million, net of $26.9 million of transportation costs) during 2005. Increased crude oil volumes from our 2005 acquisitions along with higher realized oil prices were offset primarily by the decrease in natural gas prices. The result was an increase of 3% or $49.0 million in revenue net of transportation costs.

Analysis of sales revenue[1] ($ millions)	Crude Oil	NGLs	Natural Gas	Total
2005 sales revenue	$598.4	$81.0	$ 844.3	$1,523.7
Price variance[1]	77.4	5.9	(159.6)	(76.3)
Volume variance	139.2	(3.6)	(10.3)	125.3
2006 sales revenue	**$815.0**	**$83.3**	**$ 674.4**	**$1,572.7**

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. Royalties in 2006 and 2005 were approximately 19% of oil and gas sales, net of transportation costs. Overall, royalties decreased marginally in 2006 to $293.2 million compared to $297.0 million during 2005 primarily as a result of the decrease in natural gas prices experienced over the period.

For 2007 we expect royalties to remain at approximately 19% of oil and gas sales, net of transportation costs, however this may change as a result of the Alberta government's stated intention to review the oil and gas royalty regime. Alberta royalties represented approximately 70% of our total royalties incurred during 2006 (2005 – 87%).

Operating Expenses

Operating expenses for the year ended December 31, 2006 were $8.02/BOE or $251.2 million. This represents a 3% increase over our guidance of $7.80/BOE and an 8% increase from $7.45/BOE in 2005. Cost pressures associated with the high level of industry activity have increased operating costs during 2006. The areas that were most impacted by these activity levels included scheduled facility maintenance and well servicing.

During the fourth quarter we experienced increases as a result of the timing of certain well servicing and facility maintenance programs. As well, we experienced higher natural gas processing fees at certain facilities.

We anticipate continued increases in operating costs in 2007 due to general cost escalation. As a result, we expect costs to average $8.45/BOE, representing an increase of 5% per BOE compared to 2006. Although we are seeing evidence that the cost inflation in our industry has moderated, it is too soon to tell if this trend is sustainable.

General and Administrative Expenses

G&A expenses were $1.91/BOE or $59.9 million for the year ended December 31, 2006. On a BOE basis G&A was 3% higher than our guidance of $1.85/BOE and 37% higher than $1.39/BOE in 2005.

The highly competitive marketplace resulted in challenges to recruit and retain skilled professionals. For the year ended December 31, 2006 compensation and long-term incentives increased approximately $14.0 million or $0.45/BOE compared to

the same period in 2005. Other increases included additional technology and information systems, our commitment to education funding for SAIT Polytechnic, along with ongoing regulatory compliance requirements.

For the year ended December 31, 2006, our G&A expenses included non-cash charges for our trust unit rights incentive plan of $6.3 million or $0.20/BOE compared to $3.0 million or $0.11/BOE for 2005. These amounts are determined using a binomial lattice option-pricing model. The increased volatility of our trust unit price combined with the increased number of rights outstanding, as a result of an increase in the number of employees, have impacted the non-cash cost of the plan.

The following table summarizes the cash and non-cash expenses recorded in G&A:

General and Administrative Costs ($ millions)	2006	2005
Cash	$53.6	$37.4
Trust unit rights incentive plan (non-cash)	6.3	3.0
Total G&A	$59.9	$40.4

(Per BOE)	2006	2005
Cash	$1.71	$1.28
Trust unit rights incentive plan (non-cash)	0.20	0.11
Total G&A	$1.91	$1.39

In 2007 we expect total G&A costs to be approximately $2.40/BOE, including non-cash G&A costs of approximately $0.30/BOE. The forecasted increase reflects cost pressures to recruit and retain a technically skilled labour force. It also includes increased costs associated with ongoing regulatory compliance and costs associated with planning and responding to the proposed tax on trusts.

Interest Expense

Annual interest expense increased by $6.4 million to $32.2 million compared to $25.8 million in 2005. This increase is due to higher average debt outstanding and rising interest rates during 2006. Our average borrowing rate, before the effects of hedging, for 2006 was 4.8% compared to 3.4% for 2005. At December 31, 2006, 20% of our debt was based on fixed interest rates while 80% was floating. These instruments are more fully described in Note 10.

Capital Expenditures

During the year ended December 31, 2006 we spent $491.2 million on development capital and facilities, our largest capital program to date. This was $6.2 million higher than our guidance of $485.0 million and $122.5 million or 33% higher than the $368.7 million spent in 2005. We achieved a 99% success rate with our drilling program as 361 net wells were drilled during 2006. Development in 2006 focused primarily on Bakken oil, shallow gas, coalbed methane, waterfloods, and our Joslyn oil sands property.

Property acquisitions were $51.3 million for the year ended December 31, 2006 compared to $119.9 million in 2005. Acquisitions during 2006 included $16.0 million for assets in the U.S., as well as $11.9 million and $11.7 million for properties at Copton and Gleneath respectively. There were no corporate acquisitions during 2006 whereas in 2005 we spent $584.1 million for the acquisitions of Lyco Energy Corporation ("Lyco") and TriLoch Resources Inc. ("TriLoch"). Property dispositions were $21.1 million for the year ended December 31, 2006 compared to $66.5 million for 2005. The majority of our 2006 divestments related to the sale of a 1% working interest in the Joslyn property in the amount of $19.7 million compared to the 2005 non-core divestment program which raised $66.5 million.

Capital Expenditures ($ millions)	2006	2005
Development expenditures	$380.5	$ 272.2
Plant and facilities	110.7	96.5
Development capital	491.2	368.7
Office	5.0	4.3
Sub-total	496.2	373.0
Acquisitions of oil and gas properties[1]	51.3	119.9
Corporate acquisitions	–	584.1
Dispositions of oil and gas properties[1]	(21.1)	(66.5)
Total net capital expenditures	$526.4	$1,010.5
Total capital expenditures financed with cash flow	$249.4	$ 276.4
Total capital expenditures financed with debt and equity	296.5	734.1
Total non-cash consideration for 1% sale of Joslyn project	(19.5)	–
Total net capital expenditures	$526.4	$1,010.5

(1) Net of post-closing adjustments.

The following is a summary by major property of our largest development capital expenditures during 2006 and 2005.

Property ($ millions)	Development Type	2006	2005
Sleeping Giant	Bakken oil	$116.7	$ 29.1
Joslyn and oil sands	Oil sands	39.1	33.2
Bantry	Conventional oil and shallow gas	21.7	42.0
Joarcam	Oil waterflood	20.2	16.9
Pembina 5-Way	Oil waterflood	15.7	19.8
Medicine Hat	Oil waterflood and shallow gas	14.9	11.0
Shackleton	Shallow gas	12.7	5.6
Hanna/Garden Plains	Shallow gas	12.5	18.5
Joffre	Coalbed methane	12.5	15.9
Deep Basin	Natural gas	12.4	11.6
Other	Oil and gas	212.8	165.1
Total		$491.2	$368.7

We expect total development capital expenditures in 2007 to be approximately $410 million. We plan to spend approximately $70 million on Bakken oil development, $65 million on waterflood development, $43 million on shallow natural gas and coalbed methane development and $40 million on oil sands development. We expect other conventional development costs to be approximately $192 million during 2007.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the year ended December 31, 2006 DDA&A increased to $15.38/BOE compared to $13.27/BOE during the year ended December 31, 2005. The increase was due to the inclusion of a full year of operations from our U.S. properties which were acquired in the latter half of 2005.

No impairment existed at December 31, 2006 using year-end reserves and management's estimates of future prices. Our future price estimates are more fully discussed in Note 3.

Asset Retirement Obligations

We have estimated our total future asset retirement obligations based on our net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. Our asset retirement obligation was $123.6 million at December 31, 2006 compared to $110.6 million at December 31, 2005. The increase of $13.0 million was due to our acquisition and development activity during the year combined with changes in estimated future liabilities. The remainder of the change was due to retirement costs incurred offset by accretion expense for the year. See Note 4.

The following chart compares the amortization of the asset retirement cost, accretion of the asset retirement obligation, and asset retirement obligations settled.

($ millions)	2006	2005
Amortization of the asset retirement cost	$12.6	$10.6
Accretion of the asset retirement obligation	6.2	6.3
Total amortization and accretion	$18.8	$16.9
Asset retirement obligations settled	$11.5	$ 7.8

Actual asset retirement costs will be incurred at different times compared to the recording of amortization and accretion charges. Actual asset retirement costs will be incurred over the next 66 years with the majority between 2036 and 2045. For accounting purposes, the asset retirement cost is amortized using a unit-of-production method based on proved reserves before royalties while the asset retirement obligation accretes until the time the obligation is settled.

Taxes

Future Income Taxes

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. Net income of the operating companies and the tax recovery fluctuate based on the royalty and interest payments to the Fund. Therefore, the future income tax that is recorded on the balance sheet is expected to be recovered through earnings over time.

For the year ended December 31, 2006, a future income tax recovery of $112.0 million was recorded in income compared to a future income tax expense of $15.3 million in 2005. The change year-over-year was mainly due to a lower effective tax rate for 2006, a change in discretionary tax deductions in prior years resulting in a $21.4 million recovery and recognition of a tax rate reduction for future years resulting in a $35.5 million recovery. See Note 9 for more details.

On October 31, 2006, the Government announced plans to introduce a tax on publicly traded income trusts, effective for 2011. A "Notice of Ways and Means Motion" was passed in parliament shortly after the government announcement. This notice was a one-page summary of the government's proposal and it did not identify any specific amendments to the Income Tax Act. On December 21, 2006, draft legislative proposals to implement the tax were released for comment. If the tax legislation becomes substantively enacted as proposed, future income taxes may be adjusted to include temporary differences between the accounting and tax bases of the trust's assets and liabilities.

Current Income Taxes

In our current structure, payments are made between the operating entities and the Fund which ultimately transfers both income and future income tax liability to our unitholders. As a result, no cash income taxes have been paid by our Canadian operating entities.

For the year ended December 31, 2006 our U.S. operations incurred income related taxes in the amount of $18.2 million compared to $2.8 million for the year ended December 31, 2005. The increase is primarily a result of a full year of U.S. operations in 2006.

The amount of current taxes recorded throughout the year is dependent upon the level of U.S. cash flow as well as the timing of both capital expenditures and repatriation of the funds to Canada. Our U.S. taxes as a percentage of cash flow, assuming constant working capital, were 9% for the year ended December 31, 2006 as compared to our guidance of 15%. The reduction is mainly due to funds being retained in the U.S. for the 2007 development capital program and acquisitions (see Note 13 describing the acquisition of gross overriding royalty interests in the Jonah natural gas field in Wyoming). We expect the current income and withholding taxes to average approximately 15% of cash flow from U.S. operations in 2007 assuming all funds are repatriated to Canada after U.S. development capital spending.

Tax Pools

We estimate our tax pools at December 31, 2006 to be as follows:

Pool Type ($ millions)	Trust	Operating entities	Total
COGPE	$450	$ 100	$ 550
CDE	–	300	300
UCC	–	500	500
Tax losses and other	50	400	450
Foreign tax pools	–	100	100
Total	$500	$1,400	$1,900

Net Income

Net income for the year ended December 31, 2006 was $544.8 million or $4.48 per trust unit compared to $432.0 million or $3.96 per trust unit for the year ended December 31, 2005. The $112.8 million increase in net income was primarily due to a $49.0 million increase in oil and gas sales (net of transportation costs), reduced risk management costs of $106.7 million and an increased future income tax recovery of $127.4 million, partially offset by increased DDA&A charges of $95.1 million, operating costs of $34.4 million and G&A costs of $19.6 million.

Cash Flow from Operating Activities

Cash flow from operating activities for the year ended December 31, 2006 was $863.7 million or $7.10 per trust unit compared to $774.6 million or $7.10 per trust unit for 2005. Cash flow increased during the year as a result of higher oil and gas sales and reduced cash risk management costs, offset in part by increases in operating costs and G&A expenses.

Selected Financial Results

Per BOE of production (6:1)	2006	2005
Production per day	85,779	79,727
Weighted average sales price[1]	$ 50.23	$ 52.36
Royalties	(9.36)	(10.21)
Financial contracts	(0.11)	(3.78)
Deduct: Non-cash financial contract gain	(0.99)	(1.12)
Operating costs	(8.02)	(7.45)
General and administrative	(1.91)	(1.39)
Add back: Non-cash G&A expense (trust unit rights)	0.20	0.11
Interest expense, net of interest and other income	(0.95)	(0.51)
Foreign exchange gain (loss)	0.02	(0.06)
Deduct: Non-cash foreign exchange gain	–	(0.07)
Capital taxes	(0.11)	(0.22)
Current income tax	(0.59)	(0.09)
Asset retirement obligations settled	(0.37)	(0.27)
Cash flow before changes in non-cash working capital	28.04	27.30
Asset retirement obligations settled	0.37	0.27
Non-cash items:		
Depletion, depreciation, amortization and accretion	(15.38)	(13.27)
Financial contracts	0.99	1.12
G&A expense (trust unit rights)	(0.20)	(0.11)
Foreign exchange gain	–	0.07
Future income tax recovery/(expense)	3.58	(0.53)
Total net income per BOE	$ 17.40	$ 14.85

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

Selected Canadian and U.S. Financial Results

The following table provides a geographical analysis of key financial results for 2006.

($ millions, except per unit amounts)	Canada	U.S.	Total
Daily Production Volumes			
Natural gas (Mcf/day)	265,019	5,953	270,972
Crude oil (bbls/day)	25,858	10,276	36,134
Natural gas liquids (bbls/day)	4,483	–	4,483
Total daily sales (BOE/day)	74,511	11,268	85,779
Pricing[1]			
Natural gas (per Mcf)	$ 6.79	$ 7.78	$ 6.81
Crude oil (per bbl)	59.36	67.93	61.80
Natural gas liquids (per bbl)	50.90	–	50.90
Capital			
Development capital and office	$ 378.5	$117.7	$ 496.2
Acquisitions of oil and gas properties	35.3	16.0	51.3
Dispositions of oil and gas properties	(21.1)	–	(21.1)

($ millions, except per unit amounts)	Canada	U.S.	Total
Revenues			
Oil and gas sales[1]	$1,301.0	$271.7	$1,572.7
Royalties	(241.0)	(52.2)[2]	(293.2)
Other financial contracts	(3.2)	–	(3.2)
Expenses			
Operating	$ 243.8	$ 7.4	$ 251.2
General and administrative	51.4	8.5	59.9
Depletion, depreciation, amortization and accretion	369.6	112.0	481.6
Current income taxes	–	18.2	18.2

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Royalties include U.S. state production tax.

Quarterly Financial Information

Overall oil and gas sales increased during 2005 due to higher crude oil production and higher crude oil and natural gas prices, and decreased during 2006 due to lower natural gas prices. Net income has been affected by fluctuating oil and gas prices and risk management costs, the fluctuating Canadian dollar, higher operating and G&A costs, changes in future tax provisions as well as changes to accounting policies adopted during 2005. Furthermore, changes in the fair value of our financial contracts, which are impacted by future prices, continue to cause net income to fluctuate between quarters.

Quarterly Financial Information ($ millions, except per trust unit amounts)	Oil and Gas Sales[1]	Net Income	Net Income Per Trust Unit Basic	Net Income Per Trust Unit Diluted
2006				
Fourth Quarter	$ 369.5	$110.2	$0.90	$0.89
Third Quarter	398.0	161.3	1.31	1.31
Second Quarter	403.5	146.0	1.19	1.19
First Quarter	401.7	127.3	1.08	1.07
Total	$1,572.7	$544.8	$4.48	$4.47
2005				
Fourth Quarter	$ 503.2	$150.9	$1.29	$1.28
Third Quarter	398.7	107.1	0.97	0.97
Second Quarter	320.0	108.8	1.04	1.04
First Quarter	301.8	65.2	0.63	0.62
Total	$1,523.7	$432.0	$3.96	$3.95

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments

Summary Fourth Quarter Information

In comparing the fourth quarter of 2006 with the same period in 2005:

- Net income decreased 27% to $110.2 million due to decreased natural gas prices and increased operating and G&A costs, partially offset by reduced risk management costs.
- Cash flow decreased 25% to $207.1 million in 2006 compared to $277.9 million in 2005.
- Average daily production increased 2% due to our development capital program.
- The average selling price per BOE decreased 28% due to weaker natural gas prices.

- Operating expenses increased 17% on a BOE basis to $8.52/BOE. Due to the timing of well servicing and facility maintenance programs additional costs were recorded in the fourth quarter of 2006.
- G&A expenses increased 29% on a BOE basis to $2.13/BOE due to compensation costs.
- Development capital spending decreased 12% compared to the fourth quarter of 2005 as a result of 2005 capital spending being weighted towards the fourth quarter while 2006 capital spending was evenly weighted between all four quarters.

Summary Fourth Quarter Information ($ millions, except per unit amounts)	Three Months Ended December 31, 2006	Three Months Ended December 31, 2005	% Change
Daily Production Volumes			
Natural gas (Mcf/day)	277,715	269,443	3%
Crude oil (bbls/day)	36,339	35,167	3%
Natural gas liquids (bbls/day)	4,467	5,045	(11%)
Total daily sales (BOE/day)	87,092	85,119	2%
Average Selling Price[1]			
Natural gas (per Mcf)	$ 6.58	$ 11.65	(44%)
Crude oil (per bbl)	54.53	58.41	(7%)
Natural gas liquids (per bbl)	46.15	50.56	(9%)
Per BOE	46.11	64.26	(28%)
Revenue[1]	369.5	503.2	(27%)
Per BOE	46.11	64.26	(28%)
Operating Expenses	68.3	57.1	20%
Per BOE	8.52	7.29	17%
General and Administrative Expenses	17.1	12.9[2]	33%
Per BOE	2.13	1.65[2]	29%
Net Income	110.2	150.9	(27%)
Per BOE	13.75	19.27	(29%)
Cash flow	207.1	277.9	(25%)
Per BOE	25.85	35.49	(27%)
Development Capital Spending	123.1	139.1	(12%)
Acquisitions	4.8	112.5	(96%)
Divestments	0.1	0.4	(75%)

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Certain prior year amounts have been restated to conform with current year presentation.

Three Year Summary of Key Measures

Overall, increased production volumes have resulted in higher oil and gas sales, net income and cash flow from operating activities over the last three years. The rise in crude oil and natural gas prices during 2004 and 2005 contributed to higher oil and gas sales and cash flow, however the growth of these measures moderated in 2006 as a result of lower natural gas prices. The following table provides a summary of net income, cash flow and other key measures.

($ millions, except per unit amounts)	2006	2005	2004
Oil and gas sales[1]	$1,572.7	$1,523.7	$1,124.6
Net income	544.8	432.0	258.3
Per unit (Basic)[2]	4.48	3.96	2.60
Per unit (Diluted)	4.47	3.95	2.60
Cash flow from operating activities	863.7	774.6	555.1
Per unit (Basic)[2]	7.10	7.10	5.59
Cash distributions	614.3	498.2	423.3
Per unit (Basic)[2]	5.05	4.57	4.26
Payout ratio	71%	64%	76%
Total assets	4,203.8	4,130.6	3,180.7
Long-term debt, net of cash	679.7	649.8	585.0

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) Based on weighted average trust units outstanding. Cash distributions to unitholders per unit will not correspond to the actual monthly distributions of $5.04 as a result of using the annual weighted average trust units outstanding.

Liquidity and Capital Resources

Sustainability of our Distributions and Asset Base

As an oil and gas trust we have a declining asset base and therefore rely on acquisitions and ongoing development activities to replace production and add additional reserves. Our future oil and natural gas production and reserves are highly dependent on our success in exploiting our asset base and acquiring additional reserves. To the extent we are unsuccessful in these activities our cash distributions could be reduced.

Acquisitions and development activities may be funded internally by withholding a portion of cash flow or through external sources of capital such as debt or the issuance of equity. To the extent that we withhold cash flow to finance these activities, the amount of cash distributions will be reduced. Should external sources of capital become limited or unavailable, our ability to make the necessary acquisitions and development expenditures to maintain or expand our asset base may be impaired and the amount of cash distributions may be reduced.

Distribution Policy

The amount of cash distributions is proposed by management and approved by the Board of Directors. We continually assess distribution levels with respect to forecasted cash flows, debt levels and capital spending plans. The level of cash withheld has historically varied between 10% and 40% of annual cash flow from operating activities and is dependent upon numerous factors, the most significant of which are the prevailing commodity price environment, our current levels of production, debt obligations, our access to equity markets and funding requirements for our development capital program. Although we intend to continue to make cash distributions to our unitholders, these distributions are not guaranteed.

Cash Flow from Operating Activities, Cash Distributions and Payout Ratio

Cash flow from operating activities and cash distributions are reported on the Consolidated Statements of Cash Flows.

During 2006 cash distributions of $614.3 million were funded entirely through cash flow of $863.7 million. Our payout ratio, which is calculated as cash distributions divided by cash flow, was 71% for 2006 compared to 64% in 2005.

After consideration of cash distributions, the balance of our 2006 cash flow of $249.4 million was used to fund approximately 47% of our net capital expenditures. Our remaining net capital expenditures of $296.5 million were financed from the proceeds of our March 2006 equity issue and through additional debt. For more information, refer to the Capital Expenditures section of the MD&A.

In aggregate, our 2006 cash distributions of $614.3 million and our net capital expenditures of $526.4 million totaled $1,140.7 million, or approximately 132% of our cash flow of $863.7 million. We rely on access to capital markets to the extent cash distributions and net capital expenditures exceed cash flow. Over the long term we would expect to support our distributions and capital expenditures with our cash flow; however, we would continue to fund acquisitions and growth through additional debt and equity. There will be years, especially when we are investing capital in opportunities that do not immediately generate cash flow (such as our Joslyn oil sands project) that this relationship will vary. In the oil and gas sector, because of the nature of reserve reporting, the natural reservoir declines and the risks involved in capital investment, it is difficult to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore we do not disclose maintenance capital separate from development capital spending.

For the year ended December 31, 2006 our cash distributions exceeded our net income by $69.5 million (2005 – $66.2 million). Net income includes $318.9 million of non-cash items (2005 – $342.6 million) such as DDA&A and future income taxes that do not reduce our cash flow from operations. Charges such as DDA&A are not a good proxy for the cost of maintaining our productive capacity as they are based on the historical costs of our PP&E and not the fair market value of replacing those assets within the context of the current commodity price environment. Future income taxes can fluctuate from period to period as a result of changes in tax rates, or based on the royalty, interest and dividends from our operating subsidiaries to the Fund, all of which are not indicative of the productive capacity of our entity. The level of investment in a given period may not be sufficient to replace productive capacity given the natural declines associated with oil and natural gas assets. In these instances a portion of the cash distributions paid to unitholders would represent a return of the unitholders' capital.

The following table compares cash distributions to cash flow and net income.

($ millions, except per unit amounts)	2006	2005
Cash flow from operating activities:	$863.7	$774.6
Use of cash flow:		
Cash distributions	$614.3	$498.2
Capital expenditures	249.4	276.4
	$863.7	$774.6
Excess of cash flow over cash distributions	$249.4	$276.4
Net income	$544.8	$432.0
Shortfall of net income over cash distributions	$ (69.5)	$ (66.2)
Cash distributions per weighted average trust unit	$ 5.05	$ 4.57
Payout ratio(1)	71%	64%

(1) Based on cash distributions divided by cash flow from operating activities.

Asset Retirement Costs

Actual asset retirement costs incurred in the period are deducted for purposes of calculating cash flow. Differences between actual site restoration costs incurred and the amortization of the capitalized asset retirement cost and accretion of the asset retirement obligation are discussed in the Asset Retirement Obligations section of the MD&A and Note 4.

Long-Term Debt

Long-term debt, net of cash, at December 31, 2006 was $679.7 million, an increase of $29.8 million from December 31, 2005. Long-term debt at December 31, 2006 is comprised of $348.5 million of bank indebtedness and $331.3 million of senior unsecured notes.

Our working capital, excluding cash, at December 31, 2006 increased $46.1 million compared to December 31, 2005. Current liabilities were higher in 2005 primarily due to the recording of our commodity financial instruments at fair value.

We continue to maintain a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	Year ended Dec. 31, 2006	Year ended Dec. 31, 2005
Long-term debt to trailing cash flow	0.8 x	0.8 x
Cash flow to interest expense	26.8 x	30.0 x
Long-term debt to long-term debt plus equity	20%	21%

Long-term debt is measured net of cash.
Cash flow and interest expense are 12-months trailing.

Enerplus has an $850 million bank credit facility (the "Bank Credit Facility") through its wholly-owned subsidiary EnerMark Inc. The Bank Credit Facility is an unsecured, covenant-based, three-year committed credit agreement with nine North American banks. We have the ability to extend the facility each year or repay the entire balance at the end of the three-year term. At December 31, 2006 we had $501.5 million of available borrowing capacity under this facility, which currently extends to November, 2009. This bank debt carries floating interest rates that are expected to range between 55.0 and 110.0 basis points over Bankers' Acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items.

Payments with respect to the bank facilities, senior unsecured notes and other third party debt have priority over claims of and future distributions to the unitholders. Unitholders have no direct liability should cash flow be insufficient to repay this indebtedness. The agreements governing these bank facilities and senior unsecured notes stipulate that if we default or fail to comply with certain covenants, the ability of the operating companies to make payments to the Fund and consequently the Fund's ability to make distributions to the unitholders may be restricted. As at December 31, 2006 we are in compliance with our debt covenants. Refer to our 2006 Annual Information Form for a detailed description of these covenants.

Principal payments on Enerplus' senior unsecured notes are required commencing in 2010 and 2011 and are more fully discussed in Note 7.

We anticipate that we will continue to have adequate liquidity to fund planned development capital spending during 2007 through a combination of cash flow retained by the business and debt. A portion of our $410.0 million development capital budget for 2007 is discretionary and could be revised downward in the event of a commodity price downturn or similar economic event.

Commitments

We have contracted to transport natural gas with various pipelines totaling 35.3 MMcf/day until 2008; of this amount 5 MMcf/day extends until 2015. We also have a contract to transport a minimum of 2,480 bbls/day of crude oil until 2010. These transportation contracts will cost approximately $6.4 million in 2007.

Approximately 35% of our current gas production is dedicated to aggregator sales arrangements. Under these arrangements, we receive a price based on the average netback price of the pool, net of transportation costs incurred by the aggregator for the life of the reserves.

Our office lease commitments expire between November 2009 and January 2011. Annual costs of these lease commitments, which include rent and operating fees, amount to approximately $6.7 million in 2007. The Fund's commitments, contingencies, and guarantees are more fully described in Note 11.

Enerplus has the following minimum annual commitments including long-term debt:

		Minimum Annual Commitment Each Year					Total Committed
($ millions)	Total	2007	2008	2009	2010	2011	after 2011
Bank credit facility	$348.5[1]	$ –	$ –	$348.5	$ –	$ –	$ –
Senior unsecured notes	331.3[1]	–	–	–	53.7	66.3	211.3
Pipeline commitments	28.5	6.4	5.8	3.0	2.4	2.2	8.7
Office lease	20.9	6.7	6.8	6.7	0.6	0.1	–
Total commitments[2]	$729.2	$13.1	$12.6	$358.2	$56.7	$68.6	$220.0

(1) Interest payments have not been included since future debt levels and interest rates are not known at this time.
(2) Crown and surface royalties, lease rentals, mineral taxes, and abandonment and reclamation costs (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

Accumulated Deficit

We have historically paid cash distributions in excess of accumulated earnings as cash distributions are based on cash flow generated in the period whereas accumulated earnings are based on net income which includes non-cash items such as DDA&A charges, financial contract gains and losses, unit based compensation charges and future income tax provisions.

Trust Unit Information

We had 123,151,000 trust units outstanding at December 31, 2006 compared to 117,539,000 trust units at December 31, 2005. The weighted average number of trust units outstanding during 2006 was 121,588,000 (2005 – 109,083,000). At February 10, 2007 we had 123,253,000 trust units outstanding.

On March 20, 2006 we closed an equity offering of 4,370,000 units at a price of $58.00 per unit for gross proceeds of $253,460,000 ($240,287,000 net of issuance costs).

On August 9, 2005 we announced the closing of a subscription receipt financing related to the Lyco acquisition. A total of 10,637,500 subscription receipts were issued at a price of CDN$46.25 per receipt for gross proceeds of approximately $492.0 million. With the closing of the Lyco acquisition on August 30, 2005, subscription receipt holders received one trust unit for each subscription receipt held along with the August 2005 cash distribution of $0.37 per trust unit. The distribution paid to subscription receipt holders has been included in cash distributions.

On July 1, 2005 we acquired all of the issued and outstanding shares of TriLoch in exchange for 1,633,000 trust units, a value of approximately $69.1 million after issuance costs.

In addition 1,242,000 trust units (2005 – 1,144,000) were issued pursuant to the Trust Unit Monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") and the trust unit rights plans, net of redemptions. This resulted in $55.9 million (2005 – $40.4 million) of additional equity to the Fund.

Income Taxes

The following is a general discussion of the Canadian and U.S. tax consequences of holding Enerplus trust units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Investors or potential unitholders should consult their own legal or tax advisors as to their particular tax consequences, as well as consider the Government's proposal to implement a tax on trusts.

Canadian Unitholders

The Fund qualifies as a mutual fund trust under the Income Tax Act (Canada) and accordingly, trust units of the Fund are qualified investments for RRSPs, RRIFs, RESPs, and DPSPs. Each year, the Fund has historically transferred all of its taxable income to the unitholders by way of distributions.

In computing income, unitholders are required to include the taxable portion of distributions received in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust unit less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to $nil.

We paid $5.04 per trust unit in cash distributions to unitholders on record during 2006. For Canadian tax purposes, approximately 4% of these distributions, or $0.22 per trust unit was a tax deferred return of capital, approximately 95% or $4.81 per trust unit was taxable to unitholders as other income, and less than 1% or $0.01 per trust unit was taxable eligible dividend income.

For 2007, we estimate that 95% of cash distributions may be taxable and 5% may be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon, among other things, production, commodity prices and cash flow experienced throughout the year.

U.S. Unitholders

U.S. unitholders who received cash distributions were subject to at least a 15% Canadian withholding tax. The withholding tax is applied to both the taxable portion of the distribution as computed under Canadian tax law, and the non-taxable portion of the distribution. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

The taxable portion of the cash distribution for U.S. tax purposes is determined by Enerplus in relation to its current and accumulated earnings and profits using U.S. income tax principles. The taxable portion determined is considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers, this should be a "Qualified Dividend" eligible for the reduced tax rate. We believe Enerplus should not be classified as a Passive Foreign Investment Company for U.S. income tax purposes for 2006 and 2005.

The non-taxable portion of the cash distribution is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss arising from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as gains.

We paid US$4.42 per trust unit to U.S. residents during the 2006 calendar year, of which 10% or US$0.42 per trust unit was a tax deferred return of capital and 90% or US$4.00 per unit was a taxable qualified dividend.

For 2007, we estimate that 90% of cash distributions will be taxable to most U.S. investors and 10% will be a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependent upon, among other things, production, commodity prices and cash flow experienced throughout the year.

Critical Accounting Policies

The financial statements have been prepared in accordance with GAAP. A summary of significant accounting policies is presented in Note 1. A reconciliation of differences between Canadian and United States GAAP is presented in Note 14. Most accounting policies are mandated under GAAP. However, in accounting for oil and gas activities, we have a choice between two acceptable accounting policies: the full cost and the successful efforts methods of accounting.

The Fund follows the full cost method of accounting for oil and natural gas activities. Using the full cost method of accounting, all costs of acquiring, exploring and developing oil and natural gas properties are capitalized, including unsuccessful drilling costs and administrative costs associated with acquisitions and development. Under the successful efforts method of accounting, all exploration costs, except costs associated with drilling successful exploration wells, are expensed in the period in which they are incurred. The difference between these two methodologies is not expected to be significant to the Fund's net income or net income per unit as the majority of the Fund's drilling activity is not exploration in nature and is more focused on low risk development drilling that has traditionally achieved high success rates.

Under the full cost method of accounting, an impairment test is applied to the overall carrying value of property, plant and equipment, on a country by country cost centre basis with the reserves valued using estimated future commodity prices at period end. Under the successful efforts method of accounting, the costs are aggregated on a property-by-property basis. The carrying value of each property is subject to an impairment test. Each method may generate a different carrying value of property, plant and equipment and a different net income depending on the circumstances at period end.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Reserves

The process of estimating reserves is critical to several accounting estimates. It requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of asset retirement obligations and the application of an impairment test. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income and the asset retirement obligation.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and amortized over its useful life.

Business Combinations

Management makes various assumptions in determining the fair values of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimated (a) oil and gas reserves in accordance with NI 51-101 reserve standards, and (b) future prices of oil and gas.

Commodity Prices

Management's estimates of future crude oil and natural gas prices are critical as these prices are used to determine the carrying amount of PP&E, amounts recorded for depletion, impairment in the cost centre, and the change in fair value of financial contracts.

Trust Unit Rights

Management calculates the fair value of rights granted under our trust unit rights incentive plan using a binomial lattice option-pricing model. This process involves the use of significant estimates and assumptions, which may change over time. The values calculated under the option-pricing model may not reflect the actual value realized by trust unit rights holders.

Derivative Financial Instruments

Management uses derivative financial instruments to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts are subject to fluctuation depending on the underlying commodity prices, foreign currency exchange rates and interest rates.

Recent Canadian Accounting and Related Pronouncements

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as used by public entities, being converged with International Financial Reporting Standards over a transitional period. The Accounting Standards Board is expected to develop and publish a detailed implementation plan with a transition period expected to be approximately five years. This convergence initiative is in its early stages as of the date of these annual consolidated financial statements and the Fund also has the option to adopt U.S. GAAP at any time prior to the expected conversion date. Accordingly, it would be premature to assess the impact of the initiative, if any, on the Fund at this time.

Financial Instruments, Comprehensive Income and Hedges

The Accounting Standards Board (AcSB) has issued five new accounting standards relating to the recognition, measurement, disclosure and presentation of financial instruments. The new standards comprise five handbook sections:

CICA Section 3855 – Financial Instruments – Recognition and Measurement

This standard establishes the criteria for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. It also specifies how financial instrument gains and losses are to be presented. Financial liabilities will be classified as either held-for-trading or other. Held-for-trading instruments will be recorded at fair value with realized and unrealized gains and losses reported in net income. Other instruments will be accounted for at amortized cost with gains and losses reported in net income in the period that the liability is settled.

Derivatives will be classified as held-for-trading unless designated as hedging instruments. All derivatives, including embedded derivatives that must be separately accounted for, will be recorded at fair value on the consolidated balance sheet. For derivatives that hedge the changes in fair value of an asset or liability, changes in the derivatives' fair value will be reported in net income and will be substantially offset by changes in the fair value of the hedged asset or liability attributable to the risk being hedged. For derivatives that hedge variability in cash flows, the effective portion of the changes in the derivatives' fair value will be initially recognized in other comprehensive income and the ineffective portion will be recorded in net income. The amounts temporarily recorded in other comprehensive income will subsequently be reclassified to net income in the periods when net income is affected by the variability in the cash flows of the hedged item.

CICA Section 3865 – Hedges

This standard provides optional alternative treatment to Section 3855 for entities which choose to designate qualifying transactions as hedges for accounting purposes. It will replace Accounting Guideline 13 (AcG 13) – *Hedging Relationships*, and build on Section 1560 – *Foreign Currency Translation*, by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. Retroactive application of this Section is not permitted.

CICA Section 1530 – Comprehensive Income

This standard introduces a new requirement to temporarily present certain gains and losses as part of a new earnings measurement called comprehensive income.

CICA Section 3862 – Financial Instruments – Disclosures

This standard requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks.

CICA Section 3863 – Financial Instruments – Presentation

This standard establishes presentation guidelines for financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset.

CICA sections 3855, 3865 and 1530 are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. At this time we are unable to quantify the impact these sections will have on Enerplus. These sections will result in the following upon adoption:

- Our interest rate and power swaps will be recorded on the balance sheet at fair value with the offset recorded to opening retained earnings.
- Our cross currency and interest rate swap will be recorded on the balance sheet at fair value with the offset recorded to opening retained earnings. The underlying US$175,000,000 senior notes will be translated to Canadian dollars with the offset recorded to opening retained earnings.
- Our investments in publicly traded marketable securities will be recorded on the balance sheet at fair value with the offset recorded to opening accumulated other comprehensive income.
- Amounts previously recorded in the cumulative translation adjustment will be reclassified into accumulated other comprehensive income.

CICA sections 3862 and 3863 are effective for annual and interim periods beginning on or after October 1, 2007.

Accounting Changes

The AcSB issued CICA Section 1506, *Accounting Changes*. The standard prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies and estimates, and correction of errors. The standard requires the retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impractical to determine either the period-specific effects or the cumulative effect of the change. Application is on a prospective basis and is effective for changes in accounting policies and estimates and correction of errors made in fiscal years beginning on or after January 1, 2007.

We do not expect the adoption of this standard will have any material impact on our results of operations or financial position.

Variable Interest Entities

The Emerging Issues Committee (EIC) issued EIC Abstract 163 – Determining the Variability to be Considered in Applying AcG 15. This Abstract, which is harmonized with the equivalent United States FASB Staff Position (FSP) FIN 46(R) – 6 – Determining the Variability to be Considered in Applying FASB Interpretation No. 46(R), provides guidance on how an entity should determine the variability to be considered in applying AcG 15 – Consolidation of Variable Interest Entities. The Abstract is to be applied prospectively to all entities with which an enterprise first becomes involved and to all entities previously required to be analyzed under AcG 15 when a reconsideration event has occurred beginning the first day of the first reporting period beginning on or after January 1, 2007.

We do not expect the adoption of this standard will have any material impact on our results of operations or financial position.

Risk Factors and Risk Management

Enerplus investors are participating in the net cash flow from a portfolio of crude oil and natural gas producing properties. As such, the cash distributions and the value of Enerplus units are subject to numerous risk factors. These risk factors, many of which are associated with the oil and gas industry, include, but are not limited to, the following influences:

Canadian Government Announcement on Intention to Tax Trusts

On October 31, 2006 Canada's Finance Minister announced a proposal to tax publicly traded income trusts. For existing income trusts, such as Enerplus, the Government's proposal includes a four-year transition period which would result in the tax measures being effective for 2011. For more details, see the Update on Canadian Government Announcement at the beginning of this MD&A.

Commodity Price Risk

Enerplus' operating results and financial condition are dependent on the prices we receive for our crude oil and natural gas production. These prices may fluctuate widely in response to a variety of factors including global and domestic economic conditions, weather conditions, the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American natural gas, political stability, transportation facilities, the price and availability of alternative fuels and government regulations.

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. Refer to the price risk management section in this MD&A.

Oil and Gas Reserves Risk

The value of our trust units are based on the underlying value of the oil and gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and natural gas prices may increase the risk of write-downs of our oil and gas property investments. Regulatory changes to reserve reporting practices can also result in reserve write-downs.

We strive to acquire low risk, mature properties with a high proportion of proved reserves, positive operating metrics, long reserve lives and predictable production. Similarly, we generally participate in lower-risk development projects, while farming out or monetizing higher risk exploratory prospects.

Each year, independent engineers evaluate a significant portion of our proved and probable reserves. Sproule Associates Limited ("Sproule") evaluated 90% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves, in keeping with NI 51-101 and has reviewed the remainder of the reserves internally evaluated by Enerplus. GLJ Petroleum Consultants Ltd. ("GLJ") evaluated the Joslyn bitumen reserves as they have previously performed such evaluations for the operator of the Joslyn project. DeGolyer and MacNaughton ("D&M") of Dallas, Texas, evaluated the reserves attributed to our assets in the United States. Both GLJ and D&M evaluated 100% of the reserves in their respective areas. Both GLJ and D&M utilized Sproule's forecast and constant price and cost assumptions as of December 31, 2006 in their evaluations to maintain consistency. The Reserves Committee of the Board of Directors has reviewed and approved the reserve reports of the independent evaluators.

Operational Inflation Risk

Over the last few years we have experienced inflationary pressures on both our development capital costs and our operating costs. Higher costs decrease the amount of cash flow from our operating activities which may affect the amount of distributions to unitholders.

We strive to control costs through incentive-based compensation plans that reward employees for such things as cost control and value-added initiatives. We attempt to minimize costs by exploiting our purchasing strength with suppliers. We use detailed budgeting and accounting practices to monitor costs. Multi-functional teams regularly perform integrated field reviews designed to reduce costs and increase revenues from our properties.

Despite these efforts, it can be difficult to control costs in the oil and gas industry, especially in periods of high commodity prices when the demand for goods and services is strong. Oil and gas production involves a significant amount of fixed costs that are difficult to reduce without decreasing production. In addition, approximately 36% of our production is operated by third parties. We have limited ability to influence costs on partner-operated properties.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new reserves and developing existing reserves. Acquisitions of oil and gas assets depend on our assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of our trust units.

Acquisitions are subject to investment guidelines, due diligence and review. Major acquisitions are approved by the Board of Directors and, where appropriate, independent reserve engineer evaluations are obtained.

Non-Resident Ownership and Mutual Fund Trust Status

Since our listing on the New York Stock Exchange in November of 2000, we have seen increased trading volumes and levels of ownership by non-residents of Canada. Based on information received from our transfer agent and financial intermediaries in January 2007, an estimated 70% of our outstanding trust units are held by non-residents. However, this estimate may not be accurate as it is based on certain assumptions and data from the securities industry that does not have a well-defined methodology to determine the residency of beneficial holders of securities.

Enerplus currently meets the requirements of a Mutual Fund Trust as defined in the Income Tax Act (Canada). Our trust indenture does not have a specific limit on the percentage of trust units that may be owned by non-residents.

At this time, management does not anticipate any legislative changes that would affect our status as a mutual fund trust; however, we have implemented provisions in our trust indenture to allow the Board of Directors to adopt non-resident ownership constraints, if required, in order to ensure Enerplus maintains its mutual fund trust status.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on Enerplus. Canada ratified the Kyoto Protocol in late 2002, which requires countries to reduce their emissions of carbon dioxide and other greenhouse gases. Although the Canadian federal government has not released details of any implementation plan, it has stated that it intends to set targets to limit emissions for the oil and gas industry and regulate the cost of emission credits, which could result in increased capital expenditures and operating costs.

Our operations expose us to possible regulatory changes by both Canadian and U.S. governments. As an oil and gas producer, we are subject to a broad range of regulatory requirements. Similarly, as a mutual fund trust, we have a unique structure that is vulnerable to changes in legislation or income tax law.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas through such activities as participating in industry organizations and conferences, the exchange of information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results.

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through equity and debt, and as a result distribute the majority of our cash flow to our unitholders. As such, we are dependent on continued access to the capital markets to fund our activities directed towards maintaining and increasing value for our unitholders. To the extent the cash flow retained by the Fund together with new equity and debt financing is not sufficient to cover required capital expenditures then cash distributions to unitholders may be reduced.

Enerplus has listings on the Toronto and New York stock exchanges and maintains an active investor relations program.

We maintain a prudent capital structure by retaining a portion of cash flow for capital spending and utilizing the equity markets when deemed appropriate.

Continued access to capital is dependent on our ability to maintain our track record of performance and to demonstrate the advantages of the acquisition or development program that we are financing at the time.

Environmental, Health and Safety Risk ("EHS")

Environmental health and safety risks influence the workforce, operating costs and the establishment of regulatory standards.

We have established an EHS Management System designed to:

- *provide staff with the training and resources needed to complete work safely and effectively;*
- *incorporate hazard assessment and risk management as an integral part of everyday business;*
- *monitor performance to ensure that our operations comply with legal obligations and the standards we set for ourselves; and*
- *identify and manage environmental liabilities associated with our existing asset base and potential acquisitions.*

We have a site inspections program and a corrosion risk management program designed to ensure compliance with environmental laws and regulations. We carry insurance to cover a portion of our property losses, liability and business interruption. EHS risks are reviewed regularly by the EHS committee comprised of members of the Board of Directors.

Interest Rate Exposure

The Fund has exposure to movements in interest rates. Changing interest rates can affect borrowing costs and the trust unit price of yield-based investments such as Enerplus.

We monitor the interest rate forward market and have fixed the interest rate on approximately 20% of our debt through our senior unsecured notes and interest rate swaps.

Foreign Currency Exposure

Enerplus has exposure to fluctuations in foreign currency as a result of the issuance of senior unsecured notes denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements.

We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are negatively impacted as the Canadian dollar strengthens relative to the U.S. dollar.

We have hedged our foreign currency exposure on US$175 million of senior unsecured notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt with Canadian dollar interest obligations. We have not hedged our foreign exchange exposure with respect to the US$54 million of senior unsecured notes issued in October 2003 which have U.S. dollar interest and principal payment obligations.

We have not entered into any foreign currency derivatives with respect to oil and gas sales or our U.S. operations.

Counterparty Risk

We assume customer credit risk associated with oil and gas sales, financial hedging transactions and joint venture participants.

We have established credit policies and controls designed to mitigate the risk of default or non-payment with respect to oil and gas sales, financial hedging transactions and joint venture participants. We maintain a diversified sales customer base and we review our single-entity exposure on a regular basis.

Unitholder Liability

In the past, there has been some concern that trust unitholders might be held personally liable for the indebtedness of the Fund.

Enerplus is registered in Alberta, which passed legislation in June 2005 to provide statutory protection for unitholders similar to the protection afforded shareholders in a corporation. Three other provinces (Ontario, Quebec, and Manitoba) also have statutory protection for unitholders. Our bank credit agreement and our debenture agreements do not allow the creditors to extend recourse to unitholders beyond the unitholders' equity investment in the Fund.

Recruitment and Retention of Qualified Personnel

There is strong competition in all aspects of the oil and gas industry. Enerplus competes with a substantial number of other organizations for capital, acquisitions of reserves, undeveloped lands, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in all other aspects of our operations. Other organizations may have greater technical and financial resources than Enerplus which leads to increased competition. Another rising challenge is the recruitment and retention of qualified professional staff at all levels in the organization. Increased activity within the oil and gas sector and current high commodity prices can create a competitive marketplace which presents challenges in recruiting and retaining key personnel.

In order to attract and retain qualified personnel we offer competitive compensation including performance based plans.

Corporate Governance Practices

Similar to a corporation, Enerplus has in place an active Board of Directors which is responsible for the overall governance of the Fund. The board is comprised of nine directors, eight of whom are considered independent, with the remaining non-independent director being the Chief Executive Officer. The Board continually reviews our practices and procedures and monitors the evolution of corporate governance practices in both Canada and the United States to ensure we are in compliance with all the requirements of the TSX, the NYSE and the relevant securities administrators. The Board of Directors is further supported by a number of Board committees, including an Audit and Risk Management Committee, a Corporate Governance and Nominating Committee, an Environment, Health and Safety Committee, a Compensation and Human Resources Committee and a Reserves Committee. In addition to the Board committees, we have formed an internal committee, the Management Disclosure and Oversight Committee, to enhance and ensure that we meet our increasing disclosure obligations.

Summary 2007 Outlook

Enerplus offers investors the benefits of owning a large, diversified portfolio of producing oil and natural gas properties within Canada and the United States. As such, our business prospects are closely linked to the opportunities and challenges associated with oil and natural gas production. In particular, we are strongly influenced by the price of crude oil and natural gas, both of which have been volatile in recent years. Our comments with respect to our 2007 outlook should be taken within the context of the current commodity price environment.

The following summarizes Enerplus' 2007 guidance as provided throughout this MD&A. We do not attempt to forecast commodity prices and, as a result, we do not forecast future cash flow or cash distributions. Readers are encouraged to apply their own price expectations to the following factors to arrive at an expected cash distribution.

Summary of 2007 Expectations	Target	Comments
Average annual production	85,000 BOE/day	Assumes no new acquisitions or dispositions
Exit rate December 2007 production	86,000 BOE/day	Assumes $410 million development capital spending
2007 production mix	54% gas, 42% oil, 4% NGL	
Average royalty rate	19%	Percentage of gross unhedged sales
Operating costs	$8.45/BOE	
G&A costs	$2.40/BOE	Includes non-cash charges of $0.30/BOE (unit rights plan)
U.S. income and withholding tax – cash costs	15%	Applied to net cash flow generated by U.S. operations and assumes repatriation of the funds to Canada after U.S. development capital spending
Average interest cost	5.0%	Based on current fixed rates and forward market
Payout ratio	60% – 90%	
Development capital spending	$410 million	Based on current plans and price environment

Over time we have reduced our reliance on acquisitions to supplement production declines by focusing our efforts on development capital opportunities within our existing asset base. We expect to be able to essentially maintain production in 2007 through internally generated development efforts without relying on new acquisitions.

We expect our 2007 development capital spending to be $410 million, which is 17% lower than our 2006 spending. We plan to continue to withhold a portion of our cash flow to finance this capital program and we expect the payout ratio to be within our 60-90% guidance range. We believe it is important to maintain a conservative balance sheet as a defense against commodity price changes and to be positioned to capture acquisition opportunities.

We will continue to focus on low-risk development opportunities and review our risk management strategies in response to changing prices and the economics of our acquisition and development projects.

For 2007, we estimate that 95% of cash distributions will be taxable and 5% will be a tax-deferred return of capital for our Canadian unitholders. For our U.S. unitholders, we estimate that 90% of cash distribution will be taxable and 10% will be a tax-deferred return of capital.

We are encouraged by the results from our 2005 acquisitions which have been fully integrated with our existing staff and systems. The establishment of an office in Denver continues to enhance our growing presence in the U.S. oil and gas market.

Disclosure Controls and Procedures

Under the supervision of our Chief Executive Officer and Chief Financial Officer we have evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report and concluded that our disclosure controls and procedures are effective. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Additional Information

Additional information relating to Enerplus Resources Fund, including our Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

Forward-looking Information and Statements

This management's discussion and analysis ("MD&A") contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the amount, timing and tax treatment of cash distributions to unitholders; future payout ratios; future tax treatment of income trusts such as the Fund; the volumes and estimated value of the Fund's oil and gas reserves; the volume and product mix of the Fund's oil and gas production; future oil and natural gas prices and the Fund's commodity risk management programs; the amount of future asset retirement obligations; future liquidity and financial capacity; future results from operations, cost estimates and royalty rates; future development, exploration, and acquisition and development activities and related expenditures, including with respect to both our conventional and oil sands activities.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, proposed) tax and royalty regimes; the accuracy of the estimates of the Fund's reserve volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves volumes; limited, unfavourable or no access to capital markets; increased costs; the impact of competitors; and certain other risks detailed from time to time in the Fund's pubic disclosure documents (including, without limitation, those risks identified in this MD&A and in the Fund's annual information form).

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Fund or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

management's report on internal control over financial reporting

The management of Enerplus Resources Fund is responsible for establishing and maintaining adequate internal control over financial reporting for the Fund. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2006, our internal control over financial reporting is effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

Management's assessment of the effectiveness of the Fund's internal control over financial reporting as of December 31, 2006, has been audited by Deloitte & Touche LLP, the Fund's Independent Registered Chartered Accountants, who also audited the Fund's Consolidated Financial Statements for the year ended December 31, 2006.

report of independent registered chartered accountants

To the Board of Directors and Unitholders of Enerplus Resources Fund:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Enerplus Resources Fund and subsidiaries (the "Fund") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Fund's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Fund's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Fund maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Fund maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Fund, and our report dated February 21, 2007 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Independent Registered Chartered Accountants
Calgary, Canada
February 21, 2007

management's responsibility for financial statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Resources Fund (the "Fund") have been prepared within reasonable limits of materiality and in accordance with Canadian generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 21, 2007. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by Deloitte & Touche LLP, Independent Registered Chartered Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The Independent Registered Chartered Accountants Report outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Chartered Accountants and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Fund.

Gordon J. Kerr
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 21, 2007

report of independent registered chartered accountants

To the Board of Directors and Unitholders of Enerplus Resources Fund:

We have audited the accompanying consolidated balance sheets of Enerplus Resources Fund and subsidiaries (the "Fund") as of December 31, 2006 and 2005, and the related consolidated statements of income, accumulated deficit and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

With respect to the financial statements for the year ended December 31, 2006, we conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). With respect to the financial statements for the year ended December 31, 2005, we conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enerplus Resources Fund and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for the years then ended in conformity with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Fund's internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Fund's internal control over financial reporting and an unqualified opinion on the effectiveness of the Fund's internal control over financial reporting.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Independent Registered Chartered Accountants
Calgary, Canada
February 21, 2007

consolidated balance sheets

As at December 31 (CDN$ thousands)	2006	2005
Assets		
Current assets		
Cash	$ 124	$ 10,093
Accounts receivable	175,454	170,623
Deferred financial assets (Note 2)	23,612	49,874
Other current (Note 10)	6,715	26,751
	205,905	257,341
Property, plant and equipment (Note 3)	3,726,097	3,650,327
Goodwill (Note 6)	221,578	221,234
Other assets (Notes 7 and 10)	50,224	1,721
	$4,203,804	$4,130,623
Liabilities		
Current liabilities		
Accounts payable	$ 284,286	$ 316,875
Distributions payable to unitholders	51,723	49,367
Deferred credits (Note 2)	–	57,368
	336,009	423,610
Long-term debt (Note 7)	679,774	659,918
Future income taxes (Note 9)	331,340	442,970
Asset retirement obligations (Note 4)	123,619	110,606
	1,134,733	1,213,494
Equity		
Unitholders' capital (Note 8)		
Trust Units		
Authorized: Unlimited		
Issued and Outstanding: 2006 – 123,150,820 2005 – 117,539,331	3,713,126	3,410,614
Accumulated deficit	(971,085)	(901,527)
Cumulative translation adjustment (Note 1(j))	(8,979)	(15,568)
	2,733,062	2,493,519
	$4,203,804	$4,130,623

Signed on behalf of the Board of Directors:

Douglas R. Martin
Director

Robert L. Normand
Director

consolidated statements of income

For the year ended December 31 (CDN$ thousands except per trust unit amounts)	2006	2005
Revenues		
Oil and gas sales	$1,595,324	$1,550,569
Royalties	(293,161)	(296,983)
Derivative instruments (Notes 2 and 10)		
Financial contracts – qualified hedges	–	(27,256)
Other financial contracts	(3,226)	(82,664)
Other income	2,465	11,064
	1,301,402	1,154,730
Expenses		
Operating	251,239	216,808
General and administrative (Note 8(b))	59,937	40,375
Transportation	22,611	26,915
Interest on long-term debt (Note 7)	32,168	25,791
Foreign exchange (gain)/loss	(528)	1,677
Depletion, depreciation, amortization and accretion	481,598	386,545
	847,025	698,111
Income before taxes	454,377	456,619
Capital taxes	3,393	6,486
Current taxes	18,236	2,764
Future income tax (recovery)/expense (Note 9)	(112,034)	15,328
Net Income	$ 544,782	$ 432,041
Net income per trust unit		
Basic	$4.48	$3.96
Diluted	$4.47	$3.95
Weighted average number of trust units outstanding (thousands)		
Basic	121,588	109,083
Diluted	121,858	109,371

consolidated statements of accumulated deficit

For the year ended December 31 (CDN$ thousands)	2006	2005
Accumulated income, beginning of year	$ 1,408,178	$ 976,137
Net income	544,782	432,041
Accumulated income, end of year	$ 1,952,960	$ 1,408,178
Accumulated cash distributions, beginning of year	$(2,309,705)	$(1,811,500)
Cash distributions	(614,340)	(498,205)
Accumulated cash distributions, end of year	$(2,924,045)	$(2,309,705)
Accumulated deficit, end of year	$ (971,085)	$ (901,527)

consolidated statements of cash flows

For the year ended December 31 (CDN$ thousands)	2006	2005
Operating Activities		
Net income	$ 544,782	$ 432,041
Non-cash items add/(deduct):		
Depletion, depreciation, amortization and accretion	481,598	386,545
Non-cash financial contracts (Note 2)	(31,106)	(32,679)
Non-cash foreign exchange	(32)	(2,036)
Unit based compensation (Note 8)	6,323	3,040
Future income tax (Note 9)	(112,034)	15,328
Asset retirement obligations settled (Note 4)	(11,514)	(7,829)
	878,017	794,410
Increase in non-cash operating working capital	(14,321)	(19,777)
Cash flow from operating activities	863,696	774,633
Financing Activities		
Issue of trust units, net of issue costs (Note 8)	296,189	507,209
Cash distributions to unitholders	(614,340)	(498,205)
Increase in bank credit facilities (Note 7)	19,888	76,963
Decrease in non-cash financing working capital	2,356	12,924
Cash flow from financing activities	(295,907)	98,891
Investing Activities		
Capital expenditures	(496,201)	(373,032)
Property acquisitions (Note 5)	(51,313)	(123,896)
Property dispositions	1,599	66,511
Corporate acquisitions, net of cash acquired (Note 6)	–	(483,014)
Purchase of investments	(29,172)	–
(Increase)/Decrease in non-cash investing working capital	(3,535)	51,045
Cash flow from investing activities	(578,622)	(862,386)
Effect of exchange rate changes on cash	864	(1,045)
Change in cash	(9,969)	10,093
Cash, beginning of year	10,093	–
Cash, end of year	$ 124	$ 10,093
Supplementary Cash Flow Information		
Cash income taxes paid	$ 14,060	$ 2,669
Cash interest paid	$ 34,924	$ 24,220

notes to consolidated financial statements

1. Summary of Significant Accounting Policies

The management of Enerplus Resources Fund ("Enerplus" or the "Fund") prepares the financial statements in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation between Canadian GAAP and United States of America GAAP is disclosed in Note 14. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

The Fund is an open-end investment trust created under the laws of the Province of Alberta operating pursuant to the Amended and Restated Trust Indenture between EnerMark Inc. (the Fund's wholly-owned subsidiary), Enerplus Resources Corporation ("ERC") and CIBC Mellon Trust Company as Trustee. The beneficiaries of the Fund (the "unitholders") are holders of the trust units issued by the Fund. As a trust under the Income Tax Act (Canada), Enerplus is limited to holding and administering permitted investments and making distributions to the unitholders.

The Fund's financial statements include the accounts of the Fund and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated. Many of the Fund's production activities are conducted through joint ventures and the financial statements reflect only the Fund's proportionate interest in such activities.

(b) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from the Fund to its customers based on volumes delivered and contractual delivery points and price. A portion of the properties acquired through the March 5, 2003 acquisition of PCC Energy Inc. and PCC Energy Corp. are subject to a royalty arrangement with a private company that is structured as a net profits interest. The results from operations included in the Fund's consolidated financial statements for these properties are reduced for this net profits interest.

(c) Property, Plant and Equipment ("PP&E")

The Fund follows the full cost method of accounting for petroleum and natural gas properties under which all acquisition and development costs are capitalized on a country by country cost centre basis. Such costs include land acquisition, geological, geophysical, drilling costs for productive and non-productive wells, facilities and directly related overhead charges. Repairs, maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to earnings. Proceeds from the sale of petroleum and natural gas properties are applied against the capitalized costs. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more. Net costs related to operating and administrative activities during the development of large capital projects are capitalized until commercial production has commenced.

(d) Impairment Test

A limit is placed on the aggregate carrying value of PP&E (the "impairment test"). The Fund performs an impairment test on a country by country basis. An impairment loss exists when the carrying amount of the country's PP&E exceeds the estimated undiscounted future net cash flows associated with the country's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the country's proved and probable reserves are charged to income.

(e) Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated on a country by country basis using the unit-of-production method, based on the country's share of estimated proved reserves before royalties. Reserves and production are converted to equivalent units on the basis of 6 Mcf = 1 bbl, reflecting the approximate relative energy content.

(f) Goodwill

The Fund, when appropriate, recognizes goodwill relating to corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired companies. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. To assess impairment, the fair values of the Canadian and U.S. reporting units are compared to their respective book values. If the fair value is less than the book value, a second test is performed to determine the amount of impairment. The amount of impairment is measured by allocating the fair value of the reporting unit to its identifiable assets and liabilities as if they had been acquired in a business combination for a purchase price equal to their fair value. If goodwill determined in this manner is less than the carrying value of goodwill, an impairment loss is recognized in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

(g) Asset Retirement Obligations

The Fund recognizes as a liability the estimated fair value of the future retirement obligations associated with PP&E. The fair value is capitalized and amortized over the same period as the underlying asset. The Fund estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is evaluated on a periodic basis and any adjustment to the estimate is prospectively applied. As time passes, the change in net present value of the future retirement obligation is expensed through accretion. Retirement obligations settled during the period reduce the future retirement liability. No gains or losses on retirement activities were realized, due to settlements approximating the estimates.

(h) Income Taxes

The Fund is a taxable entity under the Income Tax Act (Canada) and is taxable only on Canadian income that is not distributed or distributable to the Fund's unitholders. In the Trust structure, payments made between the Canadian operating entities and the Fund, ultimately transfers both income and future income tax liability to the unitholders. The future income tax liability associated with Canadian assets recorded on the balance sheet is recovered over time through these payments. As the Canadian operating entities transfer all of their Canadian taxable income to the Fund, no provision for current Canadian income tax has been made by any Canadian operating entity.

The U.S. operating entity is subject to U.S. income taxes on its taxable income determined under U.S. income tax rules and regulations. Repatriation of funds from U.S. operations will also be subject to applicable withholding taxes as required under U.S. tax law. A provision has been setup to reflect these current U.S. income taxes.

The Fund follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to temporary differences between the amounts reported in the financial statements of the Fund's corporate subsidiaries and their respective tax bases, using substantively enacted income tax rates. The effect of a change in these income tax rates on future income tax liabilities and assets is recognized in income during the period that the change occurs.

(i) Financial Instruments

The Fund is exposed to market risks resulting from fluctuations in commodity prices and interest rates in the normal course of operations. The Fund uses various types of financial instruments to manage these market risks. Prior to December 31, 2005, the Fund designated certain commodity contracts and interest rate swaps as qualified hedges. Effective December 31, 2005, the Fund elected to stop designating commodity contracts as qualified hedges. The fair value of the former commodity hedges has been recorded as a financial liability with an offset to deferred financial assets. The deferred financial asset will be amortized over the remaining lives of the associated financial contracts. The fair value of the financial liability will be determined at each period end with any resulting change in fair value being taken into income in that period.

The gain or loss in fair value of all financial contracts that had not previously qualified for hedge accounting are taken into income during the period of change and charged to deferred credits or deferred financial assets on the balance sheet.

Proceeds or costs realized from holding interest rate swaps are recognized at the time each transaction under a contract is settled and is recorded in interest expense. The Fund has designated the interest rate swaps as qualified hedges and these swaps are evaluated quarterly to ensure they effectively hedge the underlying interest rate.

(j) Foreign Currency Translation

The Fund's U.S. operations are self-sustaining. Assets and liabilities of these operations are translated into Canadian dollars at period end exchange rates, while revenues and expenses are converted using average rates for the period. Gains and losses from the translation into Canadian dollars are deferred and included in the cumulative translation adjustment as part of unitholders' equity.

Other monetary assets and liabilities, not related to the Fund's U.S. operations, are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. The other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expenses are translated into Canadian dollars at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

(k) Unit Based Compensation

The Fund uses the fair value method of accounting for the trust unit rights incentive plan. Under this method, the fair value of the rights is determined on the date in which fair value can reasonably be determined, generally being the grant date. This amount is charged to earnings over the vesting period of the rights, with a corresponding increase in contributed surplus. When rights are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to unitholders' capital.

2. Deferred Financial Assets and Deferred Credits

The deferred financial assets of $23,612,000 at December 31, 2006 consist of the fair value of the financial instruments of $49,268,000 less the related deferred premiums of $25,656,000.

Deferred Financial Assets ($ thousands)	
Deferred financial assets as at December 31, 2005	$ 49,874
Deferred financial credits as at December 31, 2005	(57,368)
Change in fair value – other financial contracts[1]	80,980
Amortization of deferred financial assets[2]	(49,874)
Deferred financial assets as at December 31, 2006	$ 23,612

(1) Changes in the fair value of financial contracts that do not qualify for hedge accounting are taken into income during the period as other financial contracts and reflected as an increase or decrease in the deferred financial asset or liability.

(2) Represents the amortization of the fair value of financial contracts on December 31, 2005 for which hedge accounting is no longer applied. These deferred financial assets are fully amortized at December 31, 2006.

The following table summarizes the income statement effects of other financial contracts:

Other Financial Contracts ($ thousands)	2006	2005
Change in fair value	$(80,980)	$ (35,823)
Amortization of deferred financial assets	49,874	3,144
Realized cash costs, net	34,332	115,343
Other financial contracts	$ 3,226	$ 82,664

During the year ended December 31, 2006, the Fund realized cash costs of $nil from commodity financial contracts that qualified as hedges compared to cash costs of $27,256,000 (net gains and losses) during 2005.

3. Property, Plant and Equipment

($ thousands)	2006	2005
Property, plant and equipment	$ 5,855,511	$ 5,306,137
Accumulated depletion, depreciation and accretion	(2,129,414)	(1,655,810)
Net property, plant and equipment	$ 3,726,097	$ 3,650,327

Capitalized development G&A of $14,111,000 (2005 – $11,571,000) is included in PP&E and the depletion and depreciation calculation includes future capital costs of $472,567,000 (2005 – $464,423,000) included in our reserve reports. Excluded from PP&E for the depletion and depreciation calculation is $81,183,000 (2005 – $61,795,000) related to the Joslyn development project that has not commenced commercial production.

An impairment test calculation was performed on a country by country basis on the PP&E values at December 31, 2006 in which the estimated undiscounted future net cash flows associated with the proved reserves exceeded the carrying amount of the Fund's PP&E.

The following table outlines benchmark prices and the exchange rate used in the impairment tests for both Canadian and U.S. cost centres at December 31, 2006:

Year	WTI Crude Oil[1] US$/bbl	Exchange Rate US$/CDN$	Edm Light Crude[1] CDN$/bbl	Natural Gas 30 day spot @ AECO[1] CDN$/Mcf
2007	$65.73	$0.87	$74.10	$7.72
2008	68.82	0.87	77.62	8.59
2009	62.42	0.87	70.25	7.74
2010	58.37	0.87	65.56	7.55
2011	55.20	0.87	61.90	7.72
Thereafter	+2.0%	0.87	+2.0%	+2.0%

(1) Actual prices used in the impairment test were adjusted for commodity price differentials specific to the Fund.

4. Asset Retirement Obligations

Total future asset retirement obligations were estimated by management based on the Fund's net ownership interest in wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Fund has estimated the net present value of its total asset retirement obligations to be $123,619,000 at December 31, 2006 compared to $110,606,000 at December 31, 2005 based on a total liability of $436,663,000 and $422,045,000 respectively. These payments are expected to be made over the next 66 years with the majority of costs incurred between 2036 and 2045. To calculate the present value of the asset retirement obligations for 2006 the Fund used a weighted credit-adjusted rate of approximately 6.3% and an inflation rate of 2.0%, the same as for 2005. Settlements during the year approximated our estimates and as a result, no gains or losses were recognized.

Following is a reconciliation of the asset retirement obligations:

($ thousands)	2006	2005
Asset retirement obligations, beginning of year	$110,606	$105,978
Changes in estimates	12,757	8,764
Acquisition and development activity	5,574	6,791
Dispositions	(45)	(9,413)
Asset retirement obligations settled	(11,514)	(7,829)
Accretion expense	6,241	6,315
Asset retirement obligations, end of year	$123,619	$110,606

5. Property Acquisitions

Assets of Sleeping Giant LLC ("Sleeping Giant")

On October 4, 2005 the Fund acquired all ownership interests and retired the debt of Sleeping Giant, a private U.S. company holding additional working interests in certain properties of Lyco Energy Corporation for total cash consideration of $111,914,000 which was financed through existing credit facilities. The fair value of this consideration was allocated to cash and positive working capital assumed of $5,754,000 and PP&E of $106,160,000. This acquisition has been accounted for as an asset acquisition. The operating results of Sleeping Giant subsequent to October 4, 2005 are included in the Fund's consolidated financial statements.

6. Corporate Acquisitions

The allocation to the fair value of the assets acquired and liabilities assumed plus the future income tax cost are summarized as follows:

($ thousands)	2005 Lyco	2005 TriLoch
Property, plant and equipment	$ 506,379	$ 77,786
Goodwill (with no tax base)	179,019	18,450
Future income taxes	(179,019)	(18,450)
	506,379	77,786
Cash	27,231	–
Non-cash working capital deficiency	(31,664)	(399)
Net assets acquired	$ 501,946	$ 77,387

Goodwill is comprised of the following:

Goodwill ($ thousands)	2006	2005
Balance, beginning of year	$221,234	$ 29,082
Lyco acquisition	–	179,019
TriLoch acquisition	–	18,450
Foreign exchange[(1)]	344	(5,317)
Balance, end of year	$221,578	$221,234

(1) The foreign exchange results from the translation of Lyco goodwill at the period end rate.

Lyco Energy Corporation ("Lyco")

On August 30, 2005 the Fund acquired all the outstanding common shares and retired the debt including all outstanding mandatorily redeemable preferred shares of Lyco, a private U.S. company operating in the states of Montana and North Dakota. Total consideration was approximately $501,946,000, and the Fund assumed a net working capital deficiency of $4,433,000. Goodwill of $179,019,000 was recorded based on the excess of the consideration paid over the value assigned to the identifiable assets and liabilities including the future income tax liability. The acquisition, which was financed through an equity offering and available credit facilities, has been accounted for using the purchase method of accounting for business combinations. Results from the operations of Lyco subsequent to August 30, 2005 are included in the Fund's consolidated financial statements.

TriLoch Resources Inc. ("TriLoch")

On July 1, 2005 the Fund acquired all the outstanding common shares of TriLoch, a public Alberta corporation operating in southern Alberta, in exchange for 1,632,516 trust units of the Fund with a recorded value of $69,088,000. The trust unit value was based on the weighted average price of the Fund's trust units on the Toronto Stock Exchange during the five day trading period surrounding the announcement of the TriLoch transaction. Total consideration was $77,387,000 consisting of units, deal costs and the retirement of TriLoch's bank indebtedness. The Fund also assumed a working capital deficiency of $399,000. Goodwill of $18,450,000 has been recorded as a result of the excess of the consideration paid over the value allocated to the identifiable assets and liabilities including the future income tax liability. This acquisition has been accounted for using the purchase method of accounting for business combinations. Results from the operations of TriLoch subsequent to July 1, 2005 are included in the Fund's consolidated financial statements.

7. Long-Term Debt

($ thousands)	2006	2005
Bank credit facilities (a)	$348,520	$328,632
Senior notes (b)		
US$175 million (issued June 19, 2002)	268,328	268,328
US$54 million (issued October 1, 2003)	62,926	62,958
Total long-term debt	$679,774	$659,918

(a) Unsecured Bank Credit Facility

Enerplus has an $850,000,000 unsecured covenant based three year term facility and has the ability to extend the facility each year or repay the entire balance at the end of the three year term. During 2006, the facility was extended until November 2009. At December 31, 2006, Enerplus had available credit of $501,480,000 under this facility. The facility is extendible each year with a bullet payment required at the end of the three year term. Various borrowing options are available under the facility including prime rate based advances and bankers' acceptance loans. This facility carries floating interest rates that are expected to range between 55.0 and 110.0 basis points over bankers' acceptance rates, depending on Enerplus' ratio of senior debt to earnings before interest, taxes and non-cash items. The effective interest rate on the facility for the year ended December 31, 2006 was 4.8% (2005 – 3.4%).

(b) Senior Unsecured Notes

On October 1, 2003 Enerplus issued US$54,000,000 senior unsecured notes that mature October 1, 2015. The notes have a coupon rate of 5.46% priced at par with interest paid semi-annually on April 1 and October 1 of each year. Principal payments are required in five equal installments beginning October 1, 2011 and ending October 1, 2015. Costs incurred in connection with issuing the notes in the amount of $475,000 are classified as deferred charges on the balance sheet and are being amortized as a part of depletion, depreciation, amortization and accretion ("DDA&A") over the term of the notes. At December 31, 2006, the amount remaining to be amortized associated with these costs was $346,000 (2005 – $386,000). The notes are subject to fluctuations in foreign exchange rates.

On June 19, 2002 Enerplus issued US$175,000,000 senior unsecured notes that mature June 19, 2014. The notes have a coupon rate of 6.62% priced at par, with interest paid semi-annually on June 19 and December 19 of each year. Principal payments are required in five equal installments beginning June 19, 2010 and ending June 19, 2014. Costs incurred in connection with issuing the notes in the amount of $1,892,000 are classified as deferred charges on the balance sheet and are being amortized to DDA&A over the term of the notes. At December 31, 2006, the amount remaining to be amortized was $1,177,000 (2005 – $1,335,000). Concurrent with the issuance of the notes on June 19, 2002, the Fund entered into a cross currency swap with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%.

The bank credit facility and the senior notes (the "Combined Facilities") are the legal obligation of EnerMark Inc. and are guaranteed by its subsidiaries. Payments with respect to the Combined Facilities have priority over payments to the Fund and over claims of and future distributions to the unitholders. However, unitholders have no direct liability beyond their equity investment should cash flow be insufficient to repay the Combined Facilities.

8. Fund Capital

(a) Unitholders' Capital

Trust Units

Authorized: Unlimited number of trust units

Issued: ($ thousands)	2006 Units	2006 Amount	2005 Units	2005 Amount
Balance before Contributed Surplus, beginning of year	117,539	$3,407,567	104,124	$2,826,641
Issued for cash:				
Pursuant to public offerings	4,370	240,287	10,638	466,885
Pursuant to rights plans	640	22,974	805	24,737
Trust unit rights incentive plan (non-cash) – exercised	–	3,065	–	4,629
DRIP*, net of redemptions	602	32,928	339	15,613
Issued for acquisition of corporate and property interests (non-cash)	–	–	1,633	69,062
	123,151	3,706,821	117,539	3,407,567
Contributed Surplus (Trust Unit Rights Plan)	–	6,305	–	3,047
Balance, end of year	123,151	$3,713,126	117,539	$3,410,614

* Distribution Reinvestment and Unit Purchase Plan

Contributed surplus ($ thousands)	2006	2005
Balance, beginning of year	$ 3,047	$ 4,636
Trust unit rights incentive plan (non-cash) – exercised	(3,065)	(4,629)
Trust unit rights incentive plan (non-cash) – expensed	6,323	3,040
Balance, end of year	$ 6,305	$ 3,047

On March 20, 2006 the Fund closed an equity offering of 4,370,000 units at a price of $58.00 per unit for gross proceeds of $253,460,000 ($240,287,000 net of issuance costs).

On August 9, 2005 the Fund completed a Canadian equity offering of 10,637,500 subscription receipts at a price of $46.25 per subscription receipt for gross proceeds of $491,984,000 ($466,885,000 net of issuance costs). The subscription receipts were exchanged for an equal number of trust units on August 30, 2005 upon the closing of the Lyco transaction.

On July 1, 2005 the Fund issued 1,632,516 trust units pursuant to the acquisition of TriLoch valued at $42.32 per trust unit, being the weighted average trading price of the Fund's trust units on the Toronto Stock Exchange during the five day trading period surrounding the announcement of the TriLoch transaction, for a recorded value of $69,088,000 ($69,062,000 net of issuance costs).

Pursuant to the monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP"), Canadian unitholders are entitled to reinvest cash distributions in additional trust units of the Fund. Trust units are issued at 95% of the weighted average market price on the Toronto Stock Exchange for the 20 trading days preceding a distribution payment date without service charges or brokerage fees. Eligible unitholders are also entitled to make optional cash payments to acquire additional trust units; however, the 5% discount does not apply.

Trust units are redeemable by unitholders at approximately 85% of the current market price. Redemptions are limited to $500,000 during any rolling two calendar months. Redemption requests in excess of $500,000 can be paid using investments of the Fund or a non-interest bearing instrument.

(b) Trust Unit Rights Incentive Plan

As at December 31, 2006 a total of 3,079,000 rights issued pursuant to the Trust Unit Rights Incentive Plan ("Rights Plan") were outstanding at an average exercise price of $48.53. This represents 2.5% of the total trust units outstanding of which 809,000 rights, with an average exercise price of $39.81, were exercisable. Under the Rights Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net PP&E of Enerplus at the end of such calendar quarter, may result in a reduction in the exercise price of the rights. Results for the year ended December 31, 2006 reduced the exercise price of the outstanding rights by $2.02 per trust unit of which a $0.51 reduction is effective January 2007 and a $0.50 reduction is effective April 2007. Plan members have the choice to exercise rights using the original exercise price or a reduced strike price. In certain circumstances, it may be more advantageous to use the original exercise price as it could effectively lower the plan member's tax rate on the transaction.

The Fund uses a binomial lattice option-pricing model to calculate the estimated fair value of rights granted under the plan. The following assumptions were used to arrive at the estimate of fair value:

	2006	2005
Dividend yield	9.26%	8.97%
Right's exercise price reduction	$1.61	$1.43
Volatility	25.61%	21.46%
Risk-free interest rate	4.13%	3.70%
Forfeiture rate	2.80%	4.60%

The fair value of the rights granted under the plan during 2006 ranged between 12% and 14% (2005 – 9% and 10%) of the underlying market price of a trust unit on the grant date.

During the year the Fund expensed $6,323,000 or $0.05 per unit (2005 – $3,040,000 or $0.03 per unit) of unit based compensation expense using the fair value method. The remaining future fair value of the rights of $10,113,000 at December 31, 2006 (2005 – $6,380,000) will be recognized in earnings over the remaining vesting period of the rights. Activity for the rights issued pursuant to the Rights Plan is as follows:

	2006		2005	
	Number of Rights (000's)	Weighted Average Exercise Price[1]	Number of Rights (000's)	Weighted Average Exercise Price[1]
Trust unit rights outstanding				
Beginning of year	2,621	$42.80	2,401	$34.33
Granted	1,473	54.49	1,125	53.07
Exercised	(640)	35.94	(805)	30.72
Cancelled	(375)	46.35	(100)	37.15
End of year	3,079	48.53	2,621	42.80
Rights exercisable at the end of the year	809	$39.81	643	$32.46

(1) Exercise price reflects grant prices less reduction in strike price discussed above.

The following table summarizes information with respect to outstanding rights as at December 31, 2006. Rights vest between one and three years and expire between four and six years.

Rights Outstanding at December 31, 2006 (000's)	Original Exercise Price	Exercise Price after Price Reductions	Expiry Date December 31	Rights Exercisable at December 31, 2006 (000's)
10	$24.50	$18.41	2007	10
1	26.40	20.43	2008	1
38	26.09	20.33	2008	38
6	27.70	22.14	2009	6
23	33.00	27.75	2009	23
19	36.00	31.13	2009	19
192	37.62	33.14	2009	192
14	40.70	36.61	2010	1
30	37.25	33.53	2010	8
58	38.83	35.51	2010	40
387	40.80	37.83	2010	208
80	45.55	42.90	2011	9
92	44.86	42.56	2011	16
143	49.75	47.85	2011	46
566	56.93	55.44	2011	192
178	56.55	55.54	2012	–
436	54.21	53.70	2012	–
320	56.00	56.00	2012	–
486	52.90	52.90	2012	–
3,079	$50.10	$48.53		809

(c) Basic and Diluted per Trust Unit Calculations

Net income per trust unit has been determined based on the following:

(thousands)	2006	2005
Weighted average units	121,588	109,083
Dilutive impact of rights	270	288
Diluted trust units	121,858	109,371

No rights were excluded in calculating the weighted average number of diluted units for the year ended December 31, 2006. In 2005 we excluded 132,511 rights because their exercise price was greater than the annual average unit market price of $48.08. During the last two years, outstanding rights were the only potential dilutive instrument.

9. Income Taxes

(a) Enerplus Resources Fund

The Fund is an inter-vivos trust for income tax purposes. As such, the Fund's income that is not allocated to the Fund's unitholders is taxable. The Fund intends to allocate all income to unitholders.

For 2006, the Fund had taxable income of $588,000,000 (2005 – $451,000,000) or $4.81 per trust unit (2005 – $4.05 per trust unit). Taxable income of the Fund is comprised of dividend, royalty, interest and partnership income, less deductions for Canadian oil and gas property expense ("COGPE") and trust unit issue costs.

The amounts of COGPE and issue costs remaining in the Fund at December 31, 2006 are $466,700,000 and $35,543,000 respectively (2005 – $466,700,000 and $40,109,000).

Proposed Tax on Income Trusts

On October 31, 2006 the Federal Government announced a new tax on publicly traded flow through entities including Enerplus. The tax would be applicable beginning in 2011 at the rate of 31.5% provided that Enerplus does not exceed the guidance provided on normal growth. Enerplus can issue up to $7.5 billion of new equity before 2011 without exceeding the guidance on normal growth. In addition, we understand that a trust will be able to issue equity to retire debt existing on October 31, 2006 without eroding their safe harbour equity limits.

At the present time, the proposed changes to tax legislation are not substantively enacted. Further, the timing of the enactment or the exact content of the proposed changes is difficult to predict. Therefore, no amounts in respect of this matter are reflected in the future tax liability presented on the balance sheet.

If substantively enacted, the Fund would be treated as a taxable entity resulting in the recording of future income tax assets and liabilities. Enerplus' future tax liability would be adjusted to include differences between the accounting and tax bases of the trust's assets and liabilities at the substantively enacted tax rates.

(b) Corporate Subsidiaries

The future income tax liability on the balance sheet arises as a result of the following temporary differences:

($ thousands)	**Canadian**	**Foreign**	**2006 Total**
Excess of net book value of property, plant and equipment over the underlying tax bases	**$179,770**	**$183,081**	**$362,851**
Asset retirement obligations	**(37,667)**	**–**	**(37,667)**
Deferred hedging and other	**6,963**	**(807)**	**6,156**
Future income tax liability	**$149,066**	**$182,274**	**$331,340**

($ thousands)	Canadian	Foreign	2005 Total
Excess of net book value of property, plant and equipment over the underlying tax bases	$302,610	$183,355	$485,965
Asset retirement obligations	(37,976)	–	(37,976)
Deferred hedging and other	(1,925)	(3,094)	(5,019)
Future income tax liability	$262,709	$180,261	$442,970

The provision for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

($ thousands)	2006	2005
Income before taxes	$ 454,377	$ 456,619
Computed income tax expense at the enacted rate of 34.88% (38.01% for 2005)	$ 158,487	$ 173,564
Increase (decrease) resulting from:		
Net income attributed to the Fund	(197,694)	(172,463)
Non-deductible crown royalties	11,878	30,652
Resource allowance	(11,998)	(37,047)
Amended returns and pool balances	(21,446)	16,544
Change in tax rate	(35,500)	–
Other	2,475	6,842
	$ (93,798)	$ 18,092
Future income tax (recovery)/expense	$(112,034)	$ 15,328
Current tax	$ 18,236	$ 2,764

The breakdown of our current and future income tax balances between our Canadian and Foreign operations is as follows:

For the year ended December 31, 2006 ($ thousands)	Canadian	Foreign	Total
Future income (recovery)/expense	$(113,643)	$ 1,609	$(112,034)
Current income tax	–	18,236	18,236

For the year ended December 31, 2005 ($ thousands)	Canadian	Foreign	Total
Future income expense	$8,708	$6,620	$15,328
Current income tax	–	2,764	2,764

10. Financial Instruments

The Fund's financial instruments presented on the balance sheet consist of cash, accounts receivable, deferred financial assets, other current assets, other assets, accounts payable, distributions payable to unitholders, deferred credits and long-term debt.

The carrying value of cash, accounts receivable, deferred financial assets, other assets, current liabilities and the outstanding bank credit facility balances approximate their fair value. Other current assets are comprised of prepaid expenses and marketable securities and other assets are comprised of long-term investments. Marketable securities and long-term investments are carried on the balance sheet at the lower of cost and fair value. The fair value of the marketable securities at December 31, 2006 exceeded the cost of these securities by $14,493,000. The book value of other assets at December 31, 2006 of $48,700,000 was lower than the fair value of these assets by $3,231,000.

The Fund carried US$54,000,000 of fixed rate debt. In addition, it carried US$175,000,000 of fixed rate debt that was converted to CDN$268,328,000 floating rate debt through a cross-currency swap with a syndicate of financial institutions. At December 31, 2006 the fair value of the senior unsecured notes was $62,990,000 (for the US$54,000,000 notes) and $208,217,000 (for the US$175,000,000 notes), see Note 7.

The estimated fair values have been determined based on available market information and appropriate valuation methods. The actual amounts realized may differ from these estimates.

(a) Credit Risk

Most of the Fund's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Fund manages this credit risk by entering into sales contracts with only credit-worthy counterparties and reviewing its exposure to individual entities on a regular basis. The Fund is also exposed to certain losses in the event of non-performance by counterparties to derivative financial instruments. This credit risk is managed by the Fund by selecting financially sound counterparties.

In 2006, approximately 15% of the Fund's oil and gas sales were made to a AA+ rated counterparty.

(b) Interest Rate Risk

The Fund is exposed to movements in interest rates. Long-term debt is comprised of both variable rate bank facilities and fixed rate senior notes. The Fund monitors the interest rate forward market and through the use of interest rate swaps along with the fixed-rate notes has fixed the interest rate on approximately 20% of its debt. See part (d) below.

(c) Currency Risk

The Fund is exposed to fluctuations in foreign currency as a result of its U.S. operations and the issuance of senior unsecured notes denominated in U.S. dollars. Through the use of a financial swap, the exposure on our US$175,000,000 senior unsecured notes has been converted to Canadian dollar debt. As well, the Fund has indirect exposure to fluctuations in foreign currency as crude oil sales and a portion of natural gas sales are based on U.S. dollar indices. We have not entered into any foreign currency derivatives with respect to oil and natural gas sales.

(d) Derivative Financial Instruments

The Fund uses certain derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding as at December 31, 2006 with reference to forward prices and market valuations provided by third party sources.

The fair values of derivative financial instruments are as follows:

Interest Rate Swaps

The Fund has entered into interest rate swaps on $75,000,000 of notional debt at rates varying from 4.10% to 4.61% before banking fees that are expected to range between 0.55% and 1.10%. These interest rate swaps mature between January 2007 and January 2012. The fair value of the $75,000,000 interest rate swaps as at December 31, 2006 represents an unrealized cost of $673,000. These swaps have been designated as a cash flow hedge for accounting purposes.

Cross Currency Interest Rate Swap

The fair value of the cross currency interest rate swap related to the US$175,000,000 senior unsecured notes as at December 31, 2006 represents an unrealized cost of $65,002,000 whereas the fair value of the underlying debt instrument as at December 31, 2006 represents an unrealized gain of $60,111,000. The cross currency swap has been designated as a fair value hedge for accounting purposes.

Crude Oil Instruments

Enerplus has entered into the following financial option contracts to reduce the impact of a downward movement in crude oil prices. The net premium cost of the crude oil instruments entered into as of December 31, 2006 is $20,108,000.

The following table summarizes the Fund's crude oil risk management positions at February 13, 2007:

		WTI US$/bbl	
	Daily Volumes bbls/day	Purchased Put	Fixed Price and Swaps
Term			
January 1, 2007 – December 31, 2007			
Put	5,000	$71.00	–
Put	2,500	$68.00	–
Put[1]	2,500	$65.70	–
Swap[1]	2,500	–	$66.24

[1] Financial contracts entered into during the fourth quarter of 2006.

Natural Gas Instruments

Enerplus has physical and financial contracts in place on its natural gas production as described below. The net premium cost of the natural gas instruments entered into as of December 31, 2006 is $5,548,000.

The following table summarizes the Fund's natural gas risk management positions at February 13, 2007:

		AECO CDN$/Mcf			
	Daily Volumes MMcf/day	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Term					
January 1, 2007 – March 31, 2007					
Collar	6.6	$11.45	$9.00	–	–
Collar[1]	9.5	$ 9.50	$7.00	–	–
Collar[1]	9.5	$10.66	$7.00	–	–
Costless Collar	6.6	$11.45	$7.70	–	–
Put[1]	6.6	–	$7.50	–	–
Put[1]	4.7	–	$7.39	–	–
January 1, 2007 – June 30, 2007					
Put[1]	4.7	–	$7.50	–	–
April 1, 2007 – October 31, 2007					
Collar	6.6	$10.02	$7.50	–	–
Collar	6.6	$ 9.00	$7.50	–	–
Collar[1]	9.5	$ 9.10	$7.10	–	–
Collar[1]	9.5	$ 9.15	$7.14	–	–
Collar[1]	9.5	$ 9.50	$7.20	–	–
Costless Collar[2]	4.7	$ 8.02	$7.17	–	–
Costless Collar[2]	4.7	$ 8.23	$7.28	–	–
Costless Collar[2]	4.7	$ 8.20	$7.50		
3-Way option[1]	4.7	$ 9.50	$7.75	$5.49	–
Put[1]	4.7	–	$7.28	–	–
Swap[1]	6.6	–	–	–	$7.60

	Daily Volumes MMcf/day	AECO CDN$/Mcf			
		Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Swap(1)	4.7	–	–	–	$7.33
Swap(1)	2.4	–	–	–	$7.84
Swap(1)	2.4	–	–	–	$7.96
Swap(2)	7.1	–	–	–	$7.17
Swap(2)	2.4	–	–	–	$7.70
Swap(2)	2.4	–	–	–	$7.53
Swap(2)	2.4	–	–	–	$8.35
November 1, 2007 – March 31, 2008					
Collar(1)	2.4	$ 9.95	$8.00	–	–
3-Way option(1)	4.7	$10.50	$8.20	$5.70	–
Swap(1)	4.7	–	–	–	$8.70
2007 - 2010					
Physical (escalated pricing)	2.0	–	–	–	$2.52

(1) Financial contracts entered into during the fourth quarter of 2006.
(2) Financial contracts entered into during the first quarter of 2007.

Electricity Instrument

The Fund has entered into electricity swap contracts that fix the price of electricity. These contracts have been designated as cash flow hedges and the fair value of these instruments as at December 31, 2006 represents an unrealized gain of $1,494,000. Proceeds or costs realized from the electricity contracts are recognized as operating costs.

The following table summarizes the Fund's electricity management positions at February 13, 2007:

Term	Volumes MWh	Price CDN$/MWh
January 1, 2007 – December 31, 2007	5.0	$61.50
January 1, 2007 – December 31, 2007	4.0	$62.90
January 1, 2008 – September 30, 2008	4.0	$63.00

The Fund did not enter into any new electricity contracts in the fourth quarter of 2006.

11. Commitments and Contingencies

(a) Pipeline Transportation

Enerplus has contracted to transport natural gas with various pipelines totaling 35.3 MMcf/day until 2008; of this amount 5 MMcf/day extends until 2015. Enerplus also has a contract to transport a minimum of 2,480 bbls/day of crude oil from the field to suitable marketing sales points until 2010.

(b) Oil Sands Lease #24

The Fund's acquisition of a working interest in the Joslyn project included the assumption of a proportionate share of certain contingent project debt. Effectively, this debt is comprised of principal of $3,150,000 plus accrued interest to December 31, 2006 of $1,379,000. Interest is accrued at the Bank of Canada prime business rate and is not compounded. The debt is contingent on attaining certain production hurdles with respect to development of the project. As it is still too early to determine

if these hurdles will be satisfied, no portion of the contingent debt has been accrued for in the consolidated financial statements.

(c) Office Lease

Enerplus has office lease commitments for both its Canadian and U.S. operations that expire between November 2009 and January 2011. Annual costs of these lease commitments, which include rent and operating fees, amount to approximately $6,700,000.

(d) Guarantees

(i) Corporate indemnities have been provided by the Fund to all directors and certain officers of its subsidiaries and affiliates for various items including, but not limited to, all costs to settle suits or actions due to their association with the Fund and its subsidiaries and/or affiliates, subject to certain restrictions. The Fund has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of one of the Fund's subsidiaries and/or affiliates. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) The Fund may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Fund from making a reasonable estimate of the maximum potential amounts that may be required to be paid. Management believes the resolution of these matters would not have a material adverse impact on the Fund's liquidity, consolidated financial position or results of operations.

Enerplus has the following minimum annual commitments including long-term debt:

		Minimum Annual Commitment Each Year					Total
($ thousands)	**Total**	2007	2008	2009	2010	2011	Committed after 2011
Bank credit facility	**$348,520**	$ –	$ –	$348,520	$ –	$ –	$ –
Senior unsecured notes	**331,254**	–	–	–	53,666	66,251	211,337
Pipeline commitments	**28,543**	6,364	5,788	2,952	2,444	2,275	8,720
Office lease	**20,917**	6,745	6,828	6,702	592	50	–
Total commitments	**$729,234**	$13,109	$12,616	$358,174	$56,702	$68,576	$220,057

In addition, the Fund is involved in claims and litigation arising in the normal course of business. The resolution of these claims is uncertain and there can be no assurance they will be resolved in favour of the Fund; however, management believes the resolution of these matters would not have a material adverse impact on the Fund's liquidity, consolidated financial position or results of operations.

12. Geographical Information

As at December 31, 2006 ($ thousands)	Canada	U.S.	Total
Oil and gas revenue	$1,323,631	$271,693	$1,595,324
Capital assets	3,101,277	624,820	3,726,097
Goodwill	47,532	174,046	221,578

As at December 31, 2005 ($ thousands)	Canada	U.S.	Total
Oil and gas revenue	$1,471,473	$79,096	$1,550,569
Capital assets	3,054,078	596,249	3,650,327
Goodwill	47,532	173,702	221,234

13. Events Subsequent to December 31, 2006

On January 31, 2007 Enerplus closed the acquisition of gross overriding royalty ("GORR") interests in the Jonah natural gas field in Wyoming for total consideration of US$52,000,000 (CDN$60,000,000). The full amount of the purchase price will be recorded to PP&E in 2007. This represents a GORR of approximately 0.5% on about 650 producing natural gas wells in the Jonah field.

14. Differences Between Canadian and United States Generally Accepted Accounting Principles

The Fund's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles, as they pertain to the Fund's consolidated statements differ from United States GAAP ("U.S. GAAP") as follows:

The application of U.S. GAAP would have the following effects on net income as reported:

($ thousands)	2006	2005
Net income as reported in the Consolidated Statement of Income – Canadian GAAP	$544,782	$432,041
Adjustments		
Depletion, depreciation, amortization and accretion (Note (a))	74,391	57,050
Amortization of financial derivative deferred charges (Note (b))	–	3,143
Unrealized gain (loss) on cross-currency and interest rate swap (Note (b))	1,245	(4,049)
Capitalized interest (Note (c))	3,436	–
Compensation expense (Note (d))	(2,237)	(19,732)
Income tax expense of above adjustments, including expense due to change in tax rates of $35,016 for 2006 (2005 – recovery of $2,548)	(58,234)	(16,540)
Net income before cumulative effect of change in accounting principle – U.S. GAAP	563,383	451,913
Cumulative effect of adoption of SFAS 123R (Note (d))	–	1,753
Net income – U.S. GAAP	563,383	453,666
Change in fair value of cash flow hedges, net of tax of $14,595 (2005 – $26,540 net of tax of $9,064) (Note (b))	35,287	(17,476)
Change in fair value of available for sale securities, net of tax of $1,998 (2005 – $9,229 net of tax of $3,139) (Note (e))	4,829	6,090
Change in cumulative translation adjustment (Note (g))	6,589	(15,568)
Comprehensive income	$610,088	$426,712

($ thousands)	2006	2005
Net income per trust unit before cumulative change in accounting principle		
Basic	$ 4.63	$ 4.14
Diluted	$ 4.62	$ 4.13
Cumulative effect of change in accounting principle		
Basic	$ –	$ 0.02
Diluted	$ –	$ 0.02
Net income per trust		
Basic	$ 4.63	$ 4.16
Diluted	$ 4.62	$ 4.15
Weighted average number of trust units outstanding		
Basic	121,588	109,083
Diluted	121,860	109,371
Deficit:		
Balance, beginning of year – U.S. GAAP	$(3,551,509)	$(2,366,709)
Net income – U.S. GAAP	563,383	453,666
Change in redemption value (Note (f))	586,876	(1,140,261)
Cash distributions	(614,340)	(498,205)
Balance, end of year – U.S. GAAP	$(3,015,590)	$(3,551,509)
Accumulated other comprehensive income (loss):		
Balance, beginning of year – U.S. GAAP	$ (40,772)	$ (13,818)
Change in fair value of cash flow hedges and available for sale securities, net of tax	40,116	(11,386)
Change in cumulative translation adjustment	6,589	(15,568)
Balance, end of year – U.S. GAAP	$ 5,933	$ (40,772)

Reconciliation of Accumulated Other Comprehensive Income (loss):

As at December 31 ($ thousands)	2006	2005
Fair Value of Derivatives Designated as Cash Flow Hedges:		
Interest rate swaps	$ (673)	$ (206)
Natural gas instruments	–	(36,553)
Crude oil instruments	–	(13,321)
Electricity swaps	1,494	1,019
	$ 821	$(49,061)
Other items:		
Unrealized gain on available for sale securities	17,724	10,898
Cumulative translation adjustment	(8,979)	(15,568)
Deferred income taxes	(3,633)	12,959
Accumulated other comprehensive income (loss)	$ 5,933	$(40,772)

The application of U.S. GAAP would have the following effects on the balance sheet as reported:

($ thousands)	Canadian GAAP	Increase (Decrease)	U.S. GAAP
December 31, 2006			
Assets:			
Other current assets (Note (e))	$ 6,715	$ 14,493	$ 21,208
Property, plant and equipment, net (Note (a)(c))	3,726,097	(634,553)	3,091,544
Other Assets (Note (e))	50,224	3,231	53,455
Liabilities:			
Deferred credits/Financial derivative liabilities (Note (b))	$ –	$ 64,181	$ 64,181
Trust unit rights liability (Note (d))	–	14,298	14,298
Long-term debt (Note (b))	679,774	(60,111)	619,663
Future income taxes/Deferred income taxes	331,340	(197,576)	133,764
Unitholders' mezzanine equity (Note (f))	–	5,305,098	5,305,098
Unitholder's Equity:			
Unitholders' capital (Note (f))	$3,706,821	$(3,706,821)	$ –
Contributed surplus (Note (d))	6,305	(6,305)	–
Deficit (Note (f))	(971,085)	(2,044,505)	(3,015,590)
Accumulated other comprehensive income (loss) (Note (b)(e)(g))	–	5,933	5,933
Cumulative translation adjustment (Note (g))	(8,979)	8,979	–
December 31, 2005			
Assets:			
Total current assets (Note (b)(e))	$ 257,341	$ (38,977)	$ 218,364
Property, plant and equipment, net (Note (a))	3,650,327	(712,380)	2,937,947
Liabilities:			
Deferred credits/Financial derivative liabilities (Note (b))	$ 57,368	$ 61,626	$ 118,994
Trust unit rights liability (Note (d))	–	20,654	20,654
Long-term debt (Note (b))	659,918	(56,303)	603,615
Future income taxes/Deferred income taxes	442,970	(272,403)	170,567
Unitholders' mezzanine equity (Note (f))	–	5,580,869	5,580,869
Unitholder's Equity:			
Unitholders' capital (Note (f))	$3,407,567	$(3,407,567)	$ –
Contributed surplus (Note (d))	3,047	(3,047)	–
Deficit (Note (f))	(901,527)	(2,649,982)	(3,551,509)
Accumulated other comprehensive income (loss) (Note (b)(e)(g))	–	(40,772)	(40,772)
Cumulative translation adjustment (Note (g))	(15,568)	15,568	–

(a) Property, Plant and Equipment and Depletion, Depreciation, Amortization and Accretion

Under U.S. GAAP full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proved reserves, discounted at 10% (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproved properties. Under Canadian GAAP, an impairment loss exists when the carrying amount of the Fund's PP&E exceeds the estimated undiscounted future net cash flows associated with the Fund's proved reserves. If an impairment loss is determined to exist, the costs carried on the balance sheet in excess of the discounted future net cash flows associated with the Fund's proved and probable reserves are charged to income. The application of the impairment tests under Canadian and U.S. GAAP did not result in a write-down of capitalized costs in either 2006 or 2005.

Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for DDA&A will differ in subsequent years. Historically the Fund's U.S. GAAP ceiling test write-downs have exceeded the Canadian GAAP write-downs. As a result, U.S. GAAP DDA&A charges are lower than Canadian GAAP DDA&A charges.

A U.S. GAAP difference also exists relating to the basis of measurement of proved reserves that is utilized in the depletion calculation. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices. Under Canadian GAAP, depletion charges are calculated by reference to proved reserves estimated using future prices and costs.

For the year ended December 31, 2006, DDA&A calculated under U.S. GAAP was $74,391,000 ($52,542,000 net of tax) lower than DDA&A calculated under Canadian GAAP. For the year ended December 31, 2005, DDA&A calculated under U.S. GAAP was $57,050,000 ($37,659,000 net of tax) lower than DDA&A calculated under Canadian GAAP.

(b) Derivative Instruments and Hedging

Effective January 1, 2004, the Fund prospectively adopted CICA Accounting Guideline – 13 "Hedging Relationships" ("AcG-13") and Emerging Issues Committee Abstract 128 "Accounting for Trading, Speculative or Non-hedging Derivative Financial Instruments". As a result of this adoption, derivative financial instruments not designated as hedges receive the same treatment under both Canadian and U.S. GAAP. Upon adoption of AcG-13, deferred credits and deferred charges of $21,015,000 were recognized representing the fair value of derivative financial instruments in place as of January 1, 2004 that did not qualify for hedge accounting. These deferred charges were amortized over the life of the financial instruments for Canadian GAAP and were equal to the aggregate of U.S. GAAP gains and losses incurred on these instruments prior to January 1, 2004. During 2005, the remaining $3,143,000 ($2,074,000 net of tax) of the deferred charges were amortized to income resulting in a U.S. GAAP difference.

Under Canadian GAAP, disclosure of the fair value of derivative financial instruments that qualify for hedge accounting is required with no effect on assets, liabilities or net income. Under U.S. GAAP, all derivative instruments are recognized on the balance sheet as either an asset or liability measured at fair value. Changes in the fair value are recognized in earnings unless specific hedge criteria are met.

Cash Flow Hedges

Under U.S. GAAP changes in the fair value of derivatives that are designated as cash flow hedges are recognized in earnings in the same period as the hedged item. The effective portion of the change in fair value is recognized in other comprehensive income with any ineffectiveness recognized in net income.

A U.S. GAAP difference exists as the Fund's certain interest rate and electricity swaps are designated as cash flow hedges under Canadian and U.S. GAAP.

Effective December 31, 2005 the Fund stopped designating commodity financial contracts as cash flow hedges in accordance with CICA AcG-13, "Hedging Relationships". As a result of this change, a deferred credit and deferred financial asset of $49,874,000 were recognized representing the fair value of these financial contracts. The deferred asset was amortized to income during 2006 over the remaining term of the contracts. Under U.S. GAAP, the fair value these contracts was recorded on the balance sheet at fair value with the offset recorded in accumulated other comprehensive income as at December 31, 2005. The amount recognized in accumulated other comprehensive income will be reclassified to earnings in the same period as the corresponding gains or losses associated with the hedged item. In 2006, $49,874,000 was reclassified from accumulated other comprehensive income to earnings.

Fair Value Hedges

For derivative instruments designated as fair value hedges under U.S. GAAP, both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value. The change in fair value of both items is reflected in earnings.

A U.S. GAAP difference exists as the Fund's cross-currency and interest rate swap is designated as a fair value hedge under Canadian GAAP and U.S. GAAP.

(c) Interest Capitalization

U.S. GAAP requires interest cost to be capitalized for development projects that have not reached commercial production. A U.S. GAAP difference exists as there is not a similar requirement under Canadian GAAP. For the year ended December 31, 2006 the Fund capitalized interest of $3,436,000 ($2,431,000 net of tax) (2005 – nil) related to projects under development.

(d) Unit-based Compensation

On January 1, 2005 the Fund adopted Statement of Financial Accounting Standards ("SFAS") 123R, "Share-Based Payment" using the modified prospective application of this standard and adopted the fair value method of accounting for all rights granted under the rights plan. In 2003 and 2004 the Fund accounted for the rights plan using the intrinsic method. As a result of this change, on January 1, 2005 the Fund recorded a trust unit rights liability of $12,208,000 which represented the fair value of all outstanding rights on that date, in proportion to the requisite service period rendered to that date. In addition, contributed surplus was reduced by $13,961,000, representing previously recognized compensation cost for all outstanding rights, and a recovery of $1,753,000 was recorded to cumulative effect of a change in accounting principle.

A U.S. GAAP difference exists as rights granted under our rights plan are considered liability awards for U.S. GAAP and equity awards under Canadian GAAP. The distinction between a liability award and an equity award has an impact on the related accounting treatment.

Under Canadian GAAP rights are accounted for using the fair value method for an equity award. Under this method, the fair value of the right is determined using a binomial lattice option–pricing model on the grant date and is not subsequently remeasured. This amount is charged to earnings over the vesting period of the rights, with a corresponding increase in contributed surplus. When rights are exercised, the fair value recorded in contributed surplus is recorded to unitholders' capital.

Under U.S. GAAP rights are accounted for using the fair value method for a liability award. Under this method, the trust unit rights liability is calculated based on the rights fair value determined using a binomial lattice option-pricing model at each reporting date until the date of settlement. Compensation cost for each period is based on the change in the fair value of the rights for each reporting period. When rights are exercised, the proceeds, together with the amount recorded as a trust unit rights liability, are recorded to mezzanine equity.

The following assumptions were used to arrive at the estimate of fair value as at December 31 for each the respective years:

	2006	2005
Dividend yield	9.53%	8.85%
Right's exercise price reduction	$1.67	$1.49
Volatility	27.88%	21.58%
Risk-free interest rate	3.94%	3.85%
Forfeiture rate	2.80%	4.60%

The weighted average grant date fair value of trust unit rights granted in 2006 was $6.83 per trust unit right (2005 – $5.17). The total intrinsic value of trust unit rights exercised during 2006 was $14,900,000 (2005 – $14,300,000).

As at December 31, 2006, 809,000 trust unit rights were exercisable at a weighted average reduced exercise price of $39.81 with a weighted average remaining contractual term of 3.9 years, giving an aggregate intrinsic value of $9,700,000.

The following chart details the U.S. GAAP differences related to our trust unit rights plan for the years ended December 31, 2006 and 2005.

	2006			2005		
	CDN GAAP	U.S. GAAP	Difference	CDN GAAP	U.S. GAAP	Difference
Compensation expense	$6,323,000	$ 8,560,000	$ 2,237,000	$3,040,000	$22,772,000	$19,732,000
Contributed Surplus	$6,305,000	$ –	$ (6,305,000)	$3,047,000	$ –	$ (3,047,000)
Trust unit rights liability	$ –	$14,298,000	$14,298,000	$ –	$20,654,000	$20,654,000

(e) Marketable Securities

Under Canadian GAAP the Fund accounts for its marketable securities using the cost method and only discloses the fair value.

Under U.S. GAAP marketable securities that have a readily determinable fair value are considered available for sale and are recorded on the balance sheet at fair value with changes in fair value recognized in comprehensive income.

As at December 31, 2006 available for sale marketable securities included in other current assets had a fair value of $16,758,000 (2005 – $21,713,000) and an amortized cost of $2,265,000 (2005 – $10,815,000), resulting in a gross unrealized holding gain of $14,493,000 (2005 – $10,898,000). Available for sale marketable securities included in other assets had a fair value of $13,231,000 (2005 – nil) and an amortized cost of $10,000,000 (2005 – nil), resulting in a gross unrealized holding gain of $3,231,000 (2005 – nil).

For the year ended December 31, 2006 the unrealized holding gain on available for sale securities included in accumulated other comprehensive income increased by $6,826,000 (2005 – $9,230,000).

For the year ended December 31, 2006 the Fund disposed of available for sale marketable securities for proceeds of $5,154,000 (2005 – $1,539,000) resulting in a gain of $1,425,000 (2005 – $1,158,000) being included in net income. The Fund uses the average cost method in computing realized gains or losses on sale of marketable securities.

Under U.S. GAAP securities whose fair value is not readily determinable, such as investments in private companies, are carried at cost. For the year ended December 31, 2006 the Fund had securities totaling $38,700,000 that were carried at cost (2005 – $5,440,000).

(f) Unitholders' Mezzanine Equity

U.S. GAAP difference exists as a result of the redemption feature in the Fund's trust units, which is required for the Fund to retain its Canadian mutual fund trust status. The trust units are redeemable at the option of the holder for approximately 85% of the current trading price. The amount of trust units that are redeemable for cash is limited to $500,000 in any two consecutive months. Any redemption in excess of the limit may be honored with promissory notes or other investments of the Fund. For Canadian GAAP, the trust units are considered to be permanent equity and are presented as unitholders' capital. Under U.S. GAAP, the redemption feature of the trust units excludes them from classification as permanent equity and results in the trust units being classified as mezzanine equity.

For U.S. GAAP the Fund has recorded unitholders' mezzanine equity in the amount of $5,305,098,000 for 2006 (2005 – $5,580,869,000), which represents the estimated redemption value of the trust units at 85% of the year-end market price. In addition, the Fund has recognized a deficit of $3,015,590,000 for 2006 (2005 – $3,551,509,000) resulting from eliminating unitholders' capital and replacing it with unitholders' mezzanine equity at redemption value. Changes in unitholders' mezzanine

equity in excess of trust units issued, net of redemptions, net income and cash distributions in any period are recognized as charges to the deficit.

(g) Cumulative Translation Adjustment

A U.S. GAAP difference exists relating to the cumulative translation adjustment that is generated upon translating the financial statements of the Fund's U.S. subsidiaries. For Canadian GAAP the cumulative translation adjustment is deferred and included as a separate component of equity. For U.S. GAAP this amount is recognized in comprehensive income.

The Fund's comprehensive income for the year ended December 31, 2006 includes a net decrease in the cumulative translation adjustment of $6,589,000 (2005 – increase of $15,568,000).

(h) Additional Disclosures Required under U.S. GAAP

i. The components of accounts receivable are as follows:

As at December 31 ($ thousands)	2006	2005
Oil & Gas Sales and Accruals	$111,049	$117,853
Joint Venture	62,311	48,920
Other	3,552	5,070
Less: Allowance for Doubtful Accounts	(1,458)	(1,220)
	$175,454	$170,623

ii. The components of accounts payable are as follows:

As at December 31 ($ thousands)	2006	2005
Contractors and Vendors	$137,539	$151,435
Accrued Liabilities	146,747	165,440
	$284,286	$316,875

iii. Net Oil and Gas Sales

Under U.S. GAAP oil and gas sales are presented net of royalties.

For the year ended December 31 ($ thousands)	2006	2005
Oil and Gas Sales	$1,595,324	$1,550,569
Royalties	(293,161)	(296,983)
Net Oil and Gas Sales	$1,302,163	$1,253,586

iv. Consolidated Cash Flows:

The consolidated statements of cash flows prepared in accordance with Canadian GAAP present operating cash flow before changes in non-cash working capital items. This total cannot be presented under U.S. GAAP.

The following chart details the changes in non-cash working capital:

($ thousands)	2006	2005
Accounts Receivable	$ (4,831)	$(62,627)
Other current	20,036	(17,149)
Accounts Payable	(32,589)	137,307
Distributions Payable to Unitholders	2,356	12,924
Other	(472)	(26,263)
Total Change in non-cash working capital	$(15,500)	$ 44,192
Relating to:		
Operating Activities	$(14,321)	$(19,777)
Financing Activities	2,356	12,924
Investing Activities	(3,535)	51,045
	$(15,500)	$ 44,192

v. Business Combinations:

For our business combinations completed during 2005 U.S. GAAP requires supplemental information on a pro forma basis as though the business combinations had been completed at the beginning of the period. The Fund did not complete any business combinations during 2006.

The following unaudited pro forma results are based on U.S. GAAP revenues, net income and earnings per trust unit adjusted as if the respective business combinations occurred on January 1, 2005. These results are not necessarily indicative of actual results or future performance.

For the year ended December 31, 2005 ($ thousands)	Lyco	TriLoch
Revenues	$1,267,385	$1,167,788
Net Income	$ 477,840	$ 455,662
Earnings per trust unit – Basic ($/unit)	$4.13	$4.15
Earnings per trust unit – Diluted ($/unit)	$4.12	$4.14

U.S. Pronouncements

In September 2006 the Financial Accounting Standards Board ("FASB") issued SFAS 157 – Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for fiscal years beginning after November 15, 2007. The Fund does not expect there to be a material impact on the Consolidated Financial Statements upon adoption of the Statement.

In June 2006 the FASB issued FASB Interpretation No. 48 – Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109. This guidance seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. The Fund is in the process of assessing the impact of this Interpretation.

In February 2006 the FASB issued SFAS 155 – Accounting for certain hybrid financial instruments. This Statement amends SFAS 133 on derivatives and hedging and SFAS 140 on transfers and servicing of financial assets and extinguishments of liabilities. The Statement provides a fair value measurement option for certain hybrid financial instruments containing an embedded derivative that would otherwise require bifurcation. The Statement is effective for all instruments acquired, issued or subject to a re-measurement event occurring in years beginning after September 15, 2006. The Fund does not expect there to be a material impact on the Consolidated Financial Statements upon adoption of the Statement.

5 year detailed statistical review

($ thousands, except per unit amounts)	2006	2005	2004	2003	2002
Financial					
Oil and gas sales[1]	$1,569,487	$1,413,734	$ 989,266	$ 890,011	$ 621,450
Cash distributions to unitholders	614,340	498,205	423,311	372,576	237,621
Per unit	5.04	4.47	4.20	4.29	3.25
Net income	544,782	432,041	258,316	248,046	116,621
Per unit	4.48	3.96	2.60	2.88	1.62
Total net capital expenditures	526,387	1,010,549	813,636	312,073	361,702
Total assets	4,203,804	4,130,623	3,180,748	2,661,765	2,517,976
Long-term debt, net of cash	679,650	649,825	584,991	257,701	361,011
Net debt/cash flow ratio	0.8x	0.8x	1.1x	0.6x	1.2x
Average Benchmark Pricing					
AECO natural gas (per Mcf)	$ 6.99	$ 8.48	$ 6.79	$ 6.70	$ 4.07
NYMEX natural gas (US$ per Mcf)	7.26	8.55	6.09	5.54	3.25
WTI crude oil (US$ per bbl)	66.22	56.56	41.40	31.04	26.08
CDN$/US$ exchange rate	0.88	0.83	0.77	0.72	0.64
($ per BOE except percentage data)					
Oil and Gas Economics					
Net royalty rate	19%	19%	21%	20%	21%
Weighted average price[2]	$ 50.23	$ 52.36	$ 40.90	$ 36.94	$ 27.49
Hedging[3]	(1.10)	(4.90)	(3.50)	(1.81)	(0.38)
Weighted average price[1]	49.13	47.46	37.40	35.13	27.11
Net royalty expense	9.36	10.21	8.40	7.51	5.75
Operating expense	8.02	7.45	7.14	6.73	5.86
Operating netback	31.75	29.80	21.86	20.89	15.50
General and administrative expense[3]	1.71	1.28	1.06	0.95	0.70
Management fee	–	–	–	2.29	0.94
Interest expense, net of interest and other income	0.95	0.51	0.68	0.74	0.78
Foreign exchange[3]	(0.02)	0.13	(0.01)	0.08	–
Taxes	0.70	0.31	0.24	0.26	0.23
Restoration and abandonment cash costs	0.37	0.27	0.25	0.26	0.20
Cash flow before changes in non-cash working capital	$ 28.04	$ 27.30	$ 19.64	$ 16.31	$ 12.65

(1) Net of commodity derivative instruments and transportation
(2) Net of transportation and before the effects of commodity derivative instruments
(3) Does not include non-cash portion of expense

operational statistics

The following information outlines Enerplus' gross average daily production volumes for the years indicated and our Company interest reserves based upon forecast prices and costs at December 31 each year.

	2006[(1)]	2005[(1)]	2004[(1)]	2003[(1)]	2002
Daily Production					
Oil Sands	n/a	n/a	n/a	n/a	n/a
Crude Oil (bbls/day)	36,134	29,315	25,550	24,597	23,288
NGLs (bbls/day)	4,483	4,689	4,398	4,666	4,410
Natural Gas (Mcf/day)	270,972	274,336	271,091	240,907	210,517
BOE per day	85,779	79,727	75,130	69,414	62,784
Proved Reserves					
Oil Sands	8,730	9,453	n/a	n/a	n/a
Crude Oil (Mbls)	125,048	129,745	104,408	91,063	105,247
NGLs (Mbbls)	12,690	13,084	12,776	13,571	16,035
Natural Gas (MMcf)	920,061	965,776	971,598	867,204	1,001,913
MBOE	299,812	313,245	279,117	249,168	288,267
Probable Reserves[(2)]					
Oil Sands	47,998	43,700	47,747	n/a	n/a
Crude Oil (Mbls)	34,421	31,567	26,783	27,807	16,725
NGLs (Mbbls)	3,777	3,539	3,292	3,742	2,319
Natural Gas (MMcf)	344,025	342,518	295,698	284,096	138,789
MBOE	143,533	135,892	127,105	78,898	42,175
Proved Plus Probable Reserves					
Oil Sands	56,728	53,153	47,747	n/a	n/a
Crude Oil (Mbls)	159,469	161,312	131,191	118,870	121,972
NGLs (Mbbls)	16,467	16,623	16,068	17,313	18,354
Natural Gas (MMcf)	1,264,086	1,308,294	1,267,296	1,151,300	1,140,702
MBOE	443,345	449,137	406,222	328,066	330,442
Reserve Life Index[(3)]					
Without Oil Sands:					
Proved (years)	9.8	9.6	10.1	10.6	12.0
Proved Plus Probable (years)	12.2	12.0	12.4	13.3	13.8
With Oil Sands:					
Proved (years)	10.1	9.9	10.1	10.6	12.0
Proved Plus Probable (years)	14.0	13.5	14.0	13.3	13.8

(1) 2003 - 2006 reserve information reflects NI 51-101 reporting methodology. Year 2002 information has not been restated for NI 51-101.
(2) Probable reserves for year 2002 have been risked by 50%.
(3) The Reserve Life Indices (RLI) are based upon year-end proved plus probable reserves (established reserves for the year 2002) divided by the following year's proved and proved plus probable production volumes as determined in the independent reserve engineering reports for 2003 forward and management's estimate for 2002.

supplemental reserve information

Reserve Reporting and Determination Methodologies

All reports, including our U.S. reserves, were evaluated using Canadian NI 51-101 rules. Three external, independent third party engineering firms were used to evaluate and review our reserves this year. Sproule Associates Limited ("Sproule"), our historical independent engineering evaluators, evaluated our Canadian conventional reserves. GLJ Petroleum Consultants Ltd. ("GLJ") evaluated the Joslyn SAGD bitumen reserves as they have previously performed such evaluations for the operator of the Joslyn project. DeGolyer and MacNaughton ("D&M") of Dallas, Texas, evaluated the reserves attributed to our assets in the United States. Sproule evaluated 90% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves and has reviewed the remainder of the reserves internally evaluated by Enerplus. Both GLJ and D&M evaluated 100% of the reserves in their respective areas. Both GLJ and D&M utilized Sproule's forecast price and cost assumptions as of December 31, 2006 in their evaluations to maintain consistency among our reserve reporting.

The following tables report company interest reserves that include gross working interest reserves plus owned royalty interest reserves using forecast prices. "Company interest" reserves are not a measure defined in NI 51-101 adopted by the Canadian securities regulators and does not have a standardized meaning under NI 51-101. Accordingly, our company interest reserves may not be comparable to reserves presented or disclosed by other issuers. Our reserves statement, which includes complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101 is contained within our Annual Information Form is available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com. Additionally, the Annual Information Form is part of our Form 40-F that is filed with the SEC and available on www.sec.gov.

Probable reserves are evaluated and categorized by our third party engineering firms or our own internal evaluators under the review of the third party engineering firm. Care should be used when comparing U.S. and Canadian style reserves and production reporting between companies. Under U.S. reporting, reserve estimates are calculated using prices and costs held constant at amounts in effect at the date of the reserve report and typically only include net proved reserves. Additionally, proved reserve standards in the U.S. may not be comparable to the Canadian standards. Generally, Canadian standards for reporting proved reserves may be more conservative than U.S. standards.

All evaluations of future net production revenues set forth in the tables are stated after the provision for income taxes and exclude abandonment costs on wells and facilities where reserves are not assigned or associated general and administrative costs. These schedules have been prepared on the basis that Enerplus will not pay cash income taxes in Canada in the future due to Enerplus' current structure as an income trust and Canadian tax laws currently in effect. Under our current mutual fund structure and existing tax legislation in Canada, annual taxable income is transferred from our operating entities to the Fund through interest, royalty and other payments. We, in turn, make distributions to our unitholders and therefore currently do not incur any Canadian income tax. As a result, after tax future net revenues from Canadian oil and gas reserves are equal to before tax future net revenues from Canadian oil and gas reserves. Enerplus' U.S. operations are subject to cash income taxes, and as a result Enerplus' U.S. reserves are shown net of the effect of such taxes that we estimate would be payable after taking into account inter-company debt in our structure. The Canadian federal government has announced a proposal designed to effectively tax income trusts such as Enerplus at the same level as Canadian corporations, effective for the 2011 tax year. Such proposal has not yet been approved or put in force and it is uncertain as what form, if any, changes in Canadian income tax laws will take as a result of such proposal. Any changes in Canadian income tax laws that may result from such proposal could adversely affect the estimated future net revenues associated with Enerplus' oil and gas reserves. For additional information, investors should refer to disclosure contained under the headings "General Development of Enerplus Resources Fund" and "Risk Factors - Risks Relating to Enerplus' Structure and Ownership of the Trust Units" in Enerplus' Annual Information Form.

The net estimated present value of all future net revenues at December 31, 2006 was based upon crude oil and natural gas pricing assumptions prepared by Sproule as of December 31, 2006. These prices were applied to the reserves evaluated by Sproule, GLJ and D&M. The base reference prices and exchange rates used by Sproule are detailed on the following page:

Sproule December 31, 2006 – Forecast Price Assumptions

	WTI crude oil US$/bbl	Light crude[1] Edmonton CDN$/bbl	Hardisty Heavy 12°API CDN$/bbl	Differential Between Hardisty Heavy and Bitumen[2] (Oil Sands) CDN$/bbl	Henry Hub Price US$/MMbtu	Natural Gas 30 day spot @ AECO CDN$/MMbtu	Exchange Rate US$/CDN$
2007	$65.73	$74.10	$42.98	$8.88	$7.85	$7.72	$0.87
2008	68.82	77.62	45.02	11.35	8.39	8.59	0.87
2009	62.42	70.25	40.74	12.83	7.65	7.74	0.87
2010	58.37	65.56	38.03	12.19	7.48	7.55	0.87
2011	55.20	61.90	35.90	11.66	7.63	7.72	0.87
Thereafter	2.0%	2.0%	2.0%	**	**	2.0%	0.87

(1) Edmonton refinery postings for 40 degree API, 0.4% sulphur content crude
(2) The bitumen price is derived by GLJ from Sproule's forecasts of various stream prices
** Escalation varies after 2011

Reserves Summary

The following table sets out our company interest volumes by production type and reserve category under a forecast price scenario. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property.

2006 Reserves Summary – Company Interest Volumes (Forecast Prices)

	Oil and Gas Reserves						
	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed producing							
Canada	66,458	28,932	2,479	97,869	11,434	727,596	230,569
United States	21,933	–	–	21,933	-	13,626	24,204
Total	**88,391**	**28,932**	**2,479**	**119,802**	**11,434**	**741,222**	**254,773**
Proved developed non-producing							
Canada	537	–	–	537	621	17,317	4,044
United States	871	–	–	871	–	724	992
Total	**1,408**	**–**	**–**	**1,408**	**621**	**18,041**	**5,036**
Proved undeveloped							
Canada	3,509	2,221	6,251	11,981	635	160,348	39,341
United States	587	–	–	587	–	450	662
Total	**4,096**	**2,221**	**6,251**	**12,568**	**635**	**160,798**	**40,003**
Total Proved							
Canada	70,504	31,153	8,730	110,387	12,690	905,261	273,954
United States	23,391	–	–	23,391	–	14,800	25,858
Total	**93,895**	**31,153**	**8,730**	**133,778**	**12,690**	**920,061**	**299,812**
Probable							
Canada	16,872	8,912	47,998	73,782	3,777	306,804	128,693
United States	8,637	–	–	8,637	–	37,221	14,840
Total	**25,509**	**8,912**	**47,998**	**82,419**	**3,777**	**344,025**	**143,533**
Proved plus Probable							
Canada	87,376	40,065	56,728	184,169	16,467	1,212,065	402,647
United States	32,028	–	–	32,028	–	52,021	40,698
Total	**119,404**	**40,065**	**56,728**	**216,197**	**16,467**	**1,264,086**	**443,345**

reserves reconciliation

2006 Proved Reserves – Company Interest Volumes (Forecast Prices)

Canada	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2005	73,249	32,901	9,453	115,603	13,084	952,624	287,458
Acquisitions	984	–	–	984	160	5,518	2,063
Divestments	(30)	–	(591)	(621)	(1)	(145)	(647)
Discoveries	–	48	–	48	27	4,095	757
Extensions	1,648	11	–	1,659	671	26,180	6,693
Technical Revisions	(2,191)	1,058	(132)	(1,265)	372	(4,956)	(1,717)
Economic Factors	226	58	–	284	(17)	(5,304)	(616)
Improved Recovery	2,806	327	–	3,133	30	23,981	7,159
Production	(6,188)	(3,250)	–	(9,438)	(1,636)	(96,732)	(27,196)
Proved Reserves at Dec. 31, 2006	**70,504**	**31,153**	**8,730**	**110,387**	**12,690**	**905,261**	**273,954**

United States	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2005	23,595	–	–	23,595	–	13,152	25,787
Acquisitions	401	–	–	401	–	341	458
Divestments	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions	440	–	–	440	–	384	504
Technical Revisions	584	–	–	584	–	1,732	872
Economic Factors	–	–	–	–	–	–	–
Improved Recovery	2,122	–	–	2,122	–	1,364	2,350
Production	(3,751)	–	–	(3,751)	–	(2,173)	(4,113)
Proved Reserves at Dec. 31, 2006	**23,391**	**–**	**–**	**23,391**	**–**	**14,800**	**25,858**

Total Enerplus	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2005	96,844	32,901	9,453	139,198	13,084	965,776	313,245
Acquisitions	1,385	–	–	1,385	160	5,859	2,521
Divestments	(30)	–	(591)	(621)	(1)	(145)	(647)
Discoveries	–	48	–	48	27	4,095	757
Extensions	2,088	11	–	2,099	671	26,564	7,197
Technical Revisions	(1,607)	1,058	(132)	(681)	372	(3,224)	(845)
Economic Factors	226	58	–	284	(17)	(5,304)	(616)
Improved Recovery	4,928	327	–	5,255	30	25,345	9,509
Production	(9,939)	(3,250)	–	(13,189)	(1,636)	(98,905)	(31,309)
Proved Reserves at Dec. 31, 2006	**93,895**	**31,153**	**8,730**	**133,778**	**12,690**	**920,061**	**299,812**

2006 Probable Reserves – Company Interest Volumes (Forecast Prices)

Canada	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2005	17,498	8,495	43,700	69,693	3,539	309,572	124,827
Acquisitions	451	–	–	451	72	2,219	893
Divestments	(5)	–	(2,738)	(2,743)	(1)	(13)	(2,745)
Discoveries	1	18	–	19	8	845	168
Extensions	407	9	6,935	7,351	217	9,593	9,167
Technical Revisions	(2,414)	337	101	(1,976)	(62)	(22,147)	(5,730)
Economic Factors	47	10	–	57	(5)	(1,642)	(223)
Improved Recovery	887	43	–	930	9	8,377	2,336
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2006	**16,872**	**8,912**	**47,998**	**73,782**	**3,777**	**306,804**	**128,693**

United States	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2005	5,574	–	–	5,574	–	32,946	11,065
Acquisitions	202	–	–	202	–	230	240
Divestments	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions	982	–	–	982	–	1,095	1,164
Technical Revisions	37	–	–	37	–	(1,002)	(129)
Economic Factors	–	–	–	–	–	–	–
Improved Recovery	1,842	–	–	1,842	–	3,952	2,500
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2006	**8,637**	**–**	**–**	**8,637**	**–**	**37,221**	**14,840**

Total Enerplus	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2005	23,072	8,495	43,700	75,267	3,539	342,518	135,892
Acquisitions	653	–	–	653	72	2,449	1,133
Divestments	(5)	–	(2,738)	(2,743)	(1)	(13)	(2,745)
Discoveries	1	18	–	19	8	845	168
Extensions	1,389	9	6,935	8,333	217	10,688	10,331
Technical Revisions	(2,377)	337	101	(1,939)	(62)	(23,149)	(5,859)
Economic Factors	47	10	–	57	(5)	(1,642)	(223)
Improved Recovery	2,729	43	–	2,772	9	12,329	4,836
Production	–	–	–	–	–	–	–
Probable Reserves at Dec. 31, 2006	**25,509**	**8,912**	**47,998**	**82,419**	**3,777**	**344,025**	**143,533**

reserves reconciliation

2006 Proved Plus Probable Reserves – Company Interest Volumes (Forecast Prices)

Canada	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2005	90,747	41,396	53,153	185,296	16,623	1,262,196	412,285
Acquisitions	1,435	–	–	1,435	232	7,737	2,956
Divestments	(35)	–	(3,329)	(3,364)	(2)	(158)	(3,392)
Discoveries	1	66	–	67	35	4,940	925
Extensions	2,055	20	6,935	9,010	888	35,773	15,860
Technical Revisions	(4,605)	1,395	(31)	(3,241)	310	(27,103)	(7,447)
Economic Factors	273	68	–	341	(22)	(6,946)	(839)
Improved Recovery	3,693	370	–	4,063	39	32,358	9,495
Production	(6,188)	(3,250)	–	(9,438)	(1,636)	(96,732)	(27,196)
Proved Plus Probable Reserves at Dec. 31, 2006	**87,376**	**40,065**	**56,728**	**184,169**	**16,467**	**1,212,065**	**402,647**

United States	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2005	29,169	–	–	29,169	–	46,098	36,852
Acquisitions	603	–	–	603	–	571	698
Divestments	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–
Extensions	1,422	–	–	1,422	–	1,479	1,668
Technical Revisions	621	–	–	621	–	730	743
Economic Factors	–	–	–	–	–	–	–
Improved Recovery	3,964	–	–	3,964	–	5,316	4,850
Production	(3,751)	–	–	(3,751)	–	(2,173)	(4,113)
Proved Plus Probable Reserves at Dec. 31, 2006	**32,028**	**–**	**–**	**32,028**	**–**	**52,021**	**40,698**

Total Enerplus	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Oil Sands) (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2005	119,916	41,396	53,153	214,465	16,623	1,308,294	449,137
Acquisitions	2,038	–	–	2,038	232	8,308	3,654
Divestments	(35)	–	(3,329)	(3,364)	(2)	(158)	(3,392)
Discoveries	1	66	–	67	35	4,940	925
Extensions	3,477	20	6,935	10,432	888	37,252	17,528
Technical Revisions	(3,984)	1,395	(31)	(2,620)	310	(26,373)	(6,704)
Economic Factors	273	68	–	341	(22)	(6,946)	(839)
Improved Recovery	7,657	370	–	8,027	39	37,674	14,345
Production	(9,939)	(3,250)	–	(13,189)	(1,636)	(98,905)	(31,309)
Proved Plus Probable Reserves at Dec. 31, 2006	**119,404**	**40,065**	**56,728**	**216,197**	**16,467**	**1,264,086**	**443,345**

net present value of future production revenue – forecast prices and costs (after U.S. taxes) at december 31, 2006

Conventional Reserves ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing				
Canada	6,705	4,479	3,464	2,877
United States	804	624	509	431
Total	**7,509**	**5,103**	**3,973**	**3,308**
Proved developed non-producing				
Canada	120	75	56	45
United States	25	19	16	13
Total	**145**	**94**	**72**	**58**
Proved undeveloped				
Canada	556	385	272	196
United States	26	16	10	7
Total	**582**	**401**	**282**	**203**
Total Proved				
Canada	7,381	4,939	3,792	3,118
United States	855	659	535	451
Total	**8,236**	**5,598**	**4,327**	**3,569**
Probable				
Canada	2,721	1,242	745	516
United States	419	217	126	78
Total	**3,140**	**1,459**	**871**	**594**
Total Proved Plus Probable Conventional Reserves	11,376	7,057	5,198	4,163
Bitumen (oil sands) Reserves				
Proved developed producing	20	16	13	11
Proved undeveloped	39	20	10	4
Total Proved	59	36	23	15
Probable	453	104	25	2
Total Proved plus Probable Bitumen (oil sands) Reserves	512	140	48	17
Total Conventional and Bitumen (oil sands) Reserves	11,888	7,197	5,246	4,180

net asset value

Enerplus' net asset value is measured with reference to the present value of all future net revenue from our reserves assuming current income tax laws as estimated by our independent reserve engineers, Sproule, GLJ and D&M, plus land values, adjusted for working capital and long-term debt at year-end. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserve engineers. In addition, this calculation ignores "going concern" value and assumes only the reserves identified in the reserve reports with no further acquisitions, despite our 20 year history of replacing production through acquisitions and development.

Net Asset Value – Forecast Prices and Costs (after U.S. tax) at December 31, 2006

($ millions except trust unit amounts, discounted at)	0%	5%	10%	15%
Present value of proved plus probable reserves				
Canadian Conventional	10,102	6,181	4,537	3,634
United States (after tax)	1,274	876	661	529
Bitumen (oil sands)	512	140	48	17
Total, present value of proved plus probable reserves	11,888	7,197	5,246	4,180
Undeveloped acreage				
Canada	53	53	53	53
United States	16	16	16	16
Long-term debt (net of cash)	(680)	(680)	(680)	(680)
Asset retirement obligations [1]	(194)	(95)	(24)	(11)
Net Working Capital excluding deferred financial assets and distributions payable to unitholders	(102)	(102)	(102)	(102)
Net Asset Value	**10,981**	**6,389**	**4,509**	**3,456**
Net Asset Value per Trust Unit at December 31, 2006 [2]	$ 89.17	$ 51.88	$ 36.61	$ 28.06

[1] Asset retirement obligations do not equal the amount on the balance sheet ($124 million) as the balance sheet amount uses a 6% discount rate and a portion of the ARO costs are already reflected in the present value of reserves computed by the independent engineers

[2] Based on 123,151,000 Trust Units outstanding as at December 31, 2006

finding, development and acquisition costs

FD&A costs can be calculated either including or excluding future development capital ("FDC"). FD&A costs under NI 51-101 include FDC as this provides a more representative view of the full cost of reserve additions as it accounts for future costs to bring the reserves to market. Under the historic method, FD&A costs are understated as reserves are included without taking into account the future capital expenditures required to fully develop the reserve base. We have included both the NI 51-101 method which includes FDC and the historic method for comparison purposes.

FD&A Costs Including Future Development Capital

($ millions, except per BOE amounts)	2006	2005	2004
Proved Reserves			
Excluding Oil Sands:			
Capital expenditures and net acquisitions	$ 502.0	$ 973.0	$ 803.2
Net change in future development capital	8.0	184.7	99.0
Company reserve additions (MMBOE)	18.6	53.7	57.5
Oil Sands:			
Capital expenditures and net acquisitions	19.4	33.2	8.3
Net change in future development capital	(13.6)	44.6	–
Company reserve additions (MMBOE)	(0.7)	9.5	–
FD&A costs ($/BOE)	$ 28.82	$ 19.55	$ 15.83
Three-year average FD&A costs ($/BOE) [1]	$ 19.20	$ 22.73	$ 18.85
Proved plus Probable Reserves			
Excluding Oil Sands:			
Capital expenditures and net acquisitions	$ 502.0	$ 973.0	$ 803.2
Net change in future development capital	54.4	197.7	120.7
Company reserve additions (MMBOE)	21.9	66.6	58.0
Oil Sands:			
Capital expenditures and net acquisitions	19.4	33.2	8.3
Net change in future development capital	15.6	33.4	266.1
Company reserve additions (MMBOE)	3.6	5.4	47.7
FD&A costs ($/BOE)	$ 23.19	$ 17.18	$ 11.34
Three-year average FD&A costs ($/BOE) [1]	$ 14.90	$ 13.46	$ 11.02

[1] FD&A calculated over a three-year period.

finding, development and acquisition costs

FD&A Costs Excluding Future Development Capital

($ millions, except per BOE amounts)	2006	2005	2004
Proved Reserves			
Excluding Oil Sands:			
Capital expenditures and net acquisitions	**$ 502.0**	$ 973.0	$ 803.2
Company reserve additions (MMBOE)	**18.6**	53.7	57.5
Oil Sands:			
Capital expenditures and net acquisitions	**19.4**	33.2	8.3
Company reserve additions (MMBOE)	**(0.7)**	9.5	–
FD&A costs ($/BOE)	**$ 29.13**	$ 15.92	$ 14.11
Three-year average FD&A costs ($/BOE) [1]	**$ 16.88**	$ 14.30	$ 11.62
Proved plus Probable Reserves			
Excluding Oil Sands:			
Capital expenditures and net acquisitions	**$ 502.0**	$ 973.0	$ 803.2
Company reserve additions (MMBOE)	**21.9**	66.6	58.0
Oil Sands:			
Capital expenditures and net acquisitions	**19.4**	33.2	8.3
Company reserve additions (MMBOE)	**3.6**	5.4	47.7
FD&A costs ($/BOE)	**$ 20.45**	$ 13.98	$ 7.68
Three-year average FD&A costs ($/BOE) [1]	**$ 11.51**	$ 10.09	$ 8.22

[1] Calculated as FD&A over a three-year period.

recycle ratio

Recycle ratio is calculated as operating income divided by FD&A including FDC. It is indicative of the value created for each dollar invested and accounts for the quality of reserves, operating costs and attractiveness of acquisitions and internal development capital.

(Proved plus probable reserves)	2006	2005	2004
Operating income ($/BOE)	**31.75**	29.80	21.86
Finding, development and acquisition costs including FDC ($/BOE)	**23.19**	17.18	11.34
Recycle ratio	**1.4x**	1.7x	1.9x
Three-year average recycle ratio	**1.6x**	1.8x	1.8x

production and reserves per unit

Production per debt-adjusted trust unit is measured in respect of the average daily production for the year, and the weighted average number of trust units outstanding during the year. The measurements are then debt-adjusted by assuming additional trust units are issued at quarter-end unit prices to replace long-term debt outstanding at each quarter-end. The average number of trust units created over the four quarters is then added to the weighted average number of trust units to obtain the debt-adjusted number of trust units for the year.

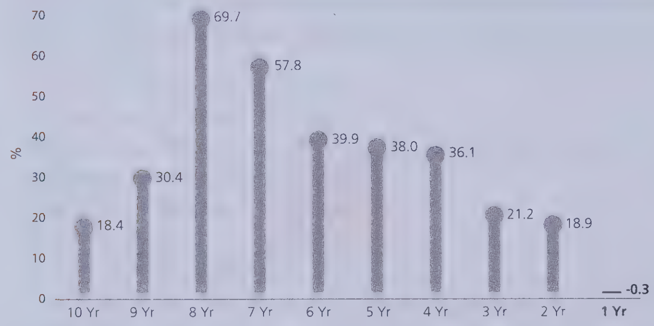
Production per Debt-Adjusted Trust Unit	**2006**	2005	2004
Average daily production	**85,779**	79,727	75,130
Debt-adjusted weighted average trust units (000's)	**132,224**	120,875	112,381
Production per debt-adjusted trust unit (BOE/unit)	**0.237**	0.241	0.245

Reserves per debt-adjusted trust unit is measured in respect of year-end proved plus probable reserves and the number of units outstanding at year-end. To eliminate the temporary timing effects of financing decisions, we have debt-adjusted these measurements by assuming we issue additional trust units at year-end prices to replace year-end long-term debt.

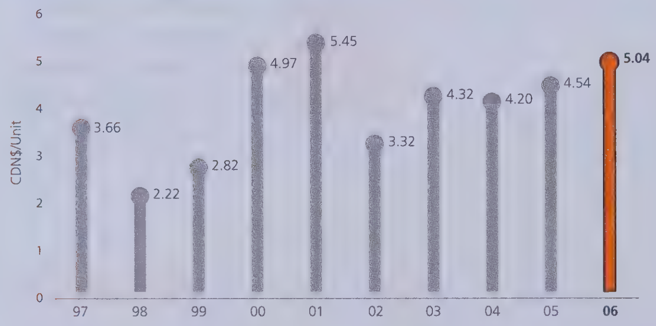
Reserves per Debt-Adjusted Trust Unit	**2006**	2005	2004
Year-end proved plus probable reserves	**443,345**	449,137	406,222
Debt-adjusted trust units outstanding at year end (000's)	**136,514**	129,172	117,541
Reserves per debt-adjusted trust unit (BOE/unit)	**3.25**	3.48	3.46

historical performance

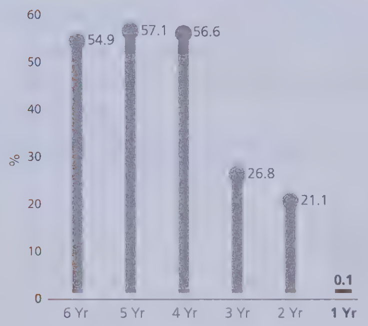
Total Return to Unitholders – CDN$ (1)



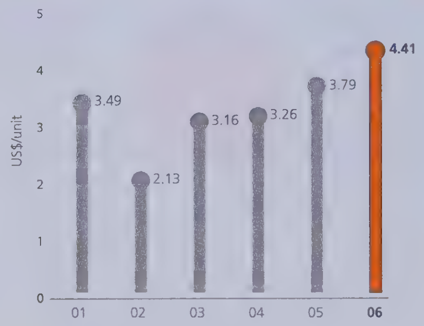
Cash Distributions Paid to Unitholders – CDN$



Total Returns to Unitholders – US$ (1)(2)



Cash Distributions Paid to Unitholders – US$ (2)



(1) Calculated using unit prices at December 31 plus or minus capital appreciation or depreciation and the total cash distributions paid during the period.

(2) Distributions to U.S. unitholders are converted to U.S. dollars on the applicable payment date. Amounts shown are prior to any amounts deducted for Canadian withholding tax. As Enerplus became listed on the NYSE in November of 2000, returns and cash distributions paid in U.S. dollars are reflected for all subsequent years only.

trust unit trading information

Toronto Stock Exchange 10 Year Trading Summary

CDN$	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997
High	**66.00**	58.55	44.54	40.72	29.00	32.86	24.60	19.20	25.50	33.00
Low	**43.86**	40.00	32.73	25.82	22.85	22.00	15.60	12.60	12.00	20.40
Close	**50.68**	55.86	43.60	39.35	28.05	24.75	22.90	16.32	12.96	23.40
Volume (000)	**82,120**	62,278	52,821	51,800	37,492	29,466	10,214	7,322	8,230	12,672

New York Stock Exchange Trading Summary

Enerplus Resources Fund began trading on the New York Stock Exchange on November 17, 2000.

US$	2006	2005	2004	2003	2002	2001	2000
High	**59.45**	50.29	36.44	31.20	19.08	23.50	15.25
Low	**38.50**	32.00	23.65	17.06	14.30	13.79	14.69
Close	**43.61**	47.98	36.31	30.44	17.75	15.56	15.25
Volume (000)	**81,677**	70,454	67,570	60,624	31,350	19,740	121

distribution reinvestment and unit purchase plan

Enerplus Resources Fund offers a convenient method for Canadian residents to reinvest cash distributions or invest additional funds into new trust units with the Distribution Reinvestment and Unit Purchase Plan ("the Plan").

Benefits of the Plan include:

- Existing unitholders can purchase new units of the Fund each month by automatically reinvesting cash distributions.
- Participants receive a 5% discount off the purchase price when reinvesting cash distributions.
- Current unitholders can also make optional cash payments each month to purchase additional units. The optional cash payments can be a minimum of $250 up to a maximum of $5,000, or the amount of cash distributions received each month.
- No commissions, service charges or brokerage fees are payable in conjunction with the Plan.

If your units are held through a broker, investment dealer or other financial intermediary, you must direct that company to enroll your units into the Plan.

To obtain more information, please contact our Investor Relations Department at 1-800-319-6462; in Calgary at (403) 298-2200; by fax at (403) 298-2211; or by email at investorrelations@enerplus.com. Information on the Plan is also available on our website at www.enerplus.com.

2006 income tax information

Information for Canadian Residents (CDN$ per Unit)

The following table outlines the breakdown of cash distributions per unit paid by Enerplus Resources Fund for the period February 20, 2006 to January 20, 2007 for Canadian income tax purposes.

Record Date	Payment Date	Total Distribution Paid	Taxable Other Income	Taxable Eligible Dividend	Return of Capital Amount
Feb 10, 2006	Feb 20, 2006	$0.420000	$0.401100	$0.000957	$0.017943
Mar 10, 2006	Mar 20, 2006	$0.420000	$0.401100	$0.000957	$0.017943
Apr 10, 2006	Apr 20, 2006	$0.420000	$0.401136	$0.000921	$0.017943
May 10, 2006	May 20, 2006	$0.420000	$0.401136	$0.000921	$0.017943
Jun 10, 2006	Jun 20, 2006	$0.420000	$0.401137	$0.000920	$0.017943
Jul 10, 2006	Jul 20, 2006	$0.420000	$0.401138	$0.000919	$0.017943
Aug 10, 2006	Aug 20, 2006	$0.420000	$0.401139	$0.000918	$0.017943
Sep 10, 2006	Sep 20, 2006	$0.420000	$0.401139	$0.000918	$0.017943
Oct 10, 2006	Oct 20, 2006	$0.420000	$0.401140	$0.000917	$0.017943
Nov 10, 2006	Nov 20, 2006	$0.420000	$0.401141	$0.000916	$0.017943
Dec 10, 2006	Dec 20, 2006	$0.420000	$0.401140	$0.000916	$0.017944
Dec 31, 2006	Jan 20, 2007	$0.420000	$0.401141	$0.000915	$0.017944
Total per unit		**$5.040000**	**$4.813587**	**$0.011095**	**$0.215318**

Information for United States Residents (US$ per Unit)

The following table outlines the breakdown of cash distributions per unit, prior to any amounts deducted for Canadian withholding tax, paid by Enerplus Resources Fund for the period January 20, 2006 to December 20, 2006 for units held through a broker or other intermediary. The amounts shown on the schedule are in U.S. dollars as converted on the applicable payment dates.

Record Date	Payment Date	Distribution Paid CDN$	Exchange Rate	Distribution Paid US$	Taxable Qualified Dividend US$	Non-Taxable Return of Capital US$
Dec 31, 2005	Jan 20, 2006	$0.42	0.859845	$0.361135	$0.327013	$0.034122
Feb 10, 2006	Feb 20, 2006	$0.42	0.870700	$0.365694	$0.331141	$0.034553
Mar 10, 2006	Mar 20, 2006	$0.42	0.855945	$0.359497	$0.325530	$0.033967
Apr 10, 2006	Apr 20, 2006	$0.42	0.875274	$0.367615	$0.332881	$0.034734
May 10, 2006	May 20, 2006	$0.42	0.891663	$0.374498	$0.339113	$0.035385
Jun 10, 2006	Jun 20, 2006	$0.42	0.890313	$0.373931	$0.338600	$0.035331
Jul 10, 2006	Jul 20, 2006	$0.42	0.880902	$0.369979	$0.335021	$0.034958
Aug 10, 2006	Aug 20, 2006	$0.42	0.891266	$0.374332	$0.338963	$0.035369
Sep 10, 2006	Sep 20, 2006	$0.42	0.885818	$0.372044	$0.336891	$0.035153
Oct 10, 2006	Oct 20, 2006	$0.42	0.886839	$0.372472	$0.337279	$0.035193
Nov 10, 2006	Nov 20, 2006	$0.42	0.870701	$0.365694	$0.331141	$0.034553
Dec 10, 2006	Dec 20, 2006	$0.42	0.868060	$0.364585	$0.330137	$0.034448
Total per unit		**$5.04**		**$4.421476**	**$4.003710**	**$0.417766**

abbreviations

In accordance with Canadian practice, production volumes, resource volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated. All reserve figures are calculated based upon company interest reserves using forecast prices and costs. "Company interest" is not a term defined in National Instrument 51-101 adopted by the Canadian Securities regulatory authorities and does not have a standardized meaning under NI 51-101 and therefore disclosure of our company interest reserves may not be comparable to disclosure of reserves by other issuers. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. Readers are also urged to review our Annual Information Form for full NI 51-101 compliant reserve and resource disclosure.

AECO	A reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf	billion cubic feet
BOE(s)/day	barrel of oil equivalent per day (6 Mcf of gas:1 BOE) (see also Definitions)
CBM	coalbed methane, otherwise known as natural gas from coal – NGC
COGPE	Canadian oil and gas property expense
COR	Certificate of Recognition
CAPP	Canadian Association of Petroleum Producers
D&M	DeGolyer and MacNaughton, an external, independent third party engineering firm
EDGAR	Electronic Data Gathering, Analysis and Retrieval system
F&D Costs	finding and development costs
FD&A Costs	finding, development and acquisition costs
FDC	future development capital
GLJ	GLJ Petroleum Consultants Ltd., an external, independent third party engineering firm
GORR	gross overriding royalty
HH	"Henry Hub" A reference to the physical storage and trading hub in Louisiana which is the delivery point for the NYMEX Natural Gas contract
IP Rate	first month initial production rate
M&A	mergers and acquisitions
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf/day	thousand cubic feet per day
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf/day	million cubic feet per day
MWh	Megawatt hour(s) of electricity
NGLs	natural gas liquids
NI 51-101	National Instrument 51-101. Oil and gas activities adopted by the Canadian Securities Regulatory Authorities (pertaining to reserve reporting in Canada)
NYSE	New York Stock Exchange
OOIP	original oil in place
P+P Reserves	proved plus probable reserves
PDP Reserves	proved developed producing reserves
RLI	reserve life index
SAGD	steam assisted gravity drainage
SEDAR	System for Electronic Document Analysis and Retrieval
Sproule	Sproule Associates Limited, an external, independent third party engineering firm
Total	Total E&P Canada Ltd., operator of Joslyn oil sands lease
TSX	Toronto Stock Exchange
WI	percentage working interest ownership
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing purposes

definitions

Bitumen	A highly viscous oil which is too thick to flow in its native state and which cannot be produced without altering its viscosity. The density of bitumen is generally less than 10 degrees API.
BOE	Barrels of oil equivalent converting 6 Mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but is a commonly used industry benchmark. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
CO_2	Carbon dioxide, a colorless, non-toxic odourless gas composed of one carbon atom and two oxygen atoms.
Established Reserves	proved plus half probable reserves applicable to years 2002 and prior.
F&D Costs	Finding and development costs. Calculated as total capital expenditures, exclusive of acquisitions or divestments, and including changes in future development capital, divided by the applicable reserve additions (proved and/or proved plus probable). It is a measure of the effectiveness of a company's capital program.
FD&A Costs	Finding, development and acquisition costs. Calculated as total capital expenditures and net acquisitions, including changes in future development capital, divided by reserve additions (proved and/or proved plus probable). It is a measure of a company's ability to add reserves in a cost effective manner.
FDC	Future development capital is defined as though costs which reflect the independent evaluators best estimate of what it will cost to bring the proved undeveloped and probable reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, and capital cost estimate revisions.
NGLs	Natural gas liquids – hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.
Oil, heavy	Oil with a density between 10 and 22.3 degrees API, or where a royalty regime exists specific to heavy oil, it is defined based upon that royalty regime.
Oil, light & medium	Oil that has a density of 22.3 degrees API or higher.
Original Oil in Place	"OOIP" - the total oil and gas estimated to have originally existed in the earth's crust in naturally occurring accumulations (also defined as "original resources" in the COGE Handbook). OOIP includes both discovered and undiscovered resources, and there is no certainty that any portion of the undiscovered resources will be discovered and, if discovered, that any volumes will be economically viable or technically feasible to recover or produce. OOIP also includes volumes that have already been produced from such accumulations. Investors should not unduly rely upon estimates of OOIP in terms of assessing the Fund's reserves or recoverable resources. All estimated of OOIP contained in this Annual Report are based upon management's internal estimates.
Operating Income	Calculated as revenues from oil and gas sales less cash hedging costs, transportation costs, royalties and operating costs.
Production, gross	Our working interest (operated and non-operated) share of production before the deduction of any royalty interest production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are gross production volumes.
Production per Debt-Adjusted Unit	Production per unit is measured in respect of the average production for the year, and the weighted average number of trust units outstanding during the year. The measurements are then debt-adjusted by assuming additional trust units are issued at quarter-end unit prices to replace long-term debt outstanding at each quarter-end. The average number of trust units created over the four quarters is then added to the weighted average number of trust units to obtain the debt-adjusted number of trust units for the year.

definitions

Recycle Ratio	Calculated as operating income per BOE divided by FD&A costs per BOE. It is an indication of the value creation of each dollar invested.
Reserve Life Index, Proved	Calculated as proved reserves at year-end divided by the following year's estimated proved production volumes as determined by the independent reserve engineering report for 2003 and forward, and management's estimate for all prior years.
Reserve Life Index, Proved plus Probable	Calculated as proved plus probable reserves at year-end (established reserves for years 2002 and prior) divided by the following year's estimated proved plus probable production volumes as determined by the independent reserve engineering report for 2003 and forward, and management's estimate for all prior years.
Reserves, Company Interest	Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves, but inclusive of any royalty interest reserves owned by Enerplus. Unless otherwise stated, reserve volumes utilized in any discussions or calculations are company interest reserves. "Company interest" is not a term defined in National Instrument 51-101 adopted by the Canadian Securities regulatory authorities and does not have a standardized meaning under NI 51-101 and therefore disclosure of our company interest reserves may not be comparable to disclosure of reserves by other issuers.
Reserves, Gross	Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves, but exclusive of royalty interest reserves owned by Enerplus.
Reserves, Net	Our working interest (operated and non-operated) share of reserves after the deduction of royalty interest reserves, but inclusive of any royalty interest reserves owned by Enerplus.
Reserves per Debt-Adjusted Unit	Reserves per trust unit are measured in respect of year-end proved plus probable reserves and the number of trust units outstanding at year-end. To eliminate the temporary timing effects of financing decisions, we have debt-adjusted these measurements by assuming we issue additional trust units at year-end prices to replace year-end long-term debt.
Reserves, Probable	Additional reserves, calculated in accordance with NI 51-101, that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
Reserves, Proved	Reserves that can be estimated with a high degree of certainty to be recoverable in accordance with NI 51-101. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
Reserves, Proved Developed Non-Producing	Reserves that have either not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
Reserves, Proved Developed Producing	Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
Reserves, Proved Undeveloped	Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production.
SAGD	Steam assisted gravity drainage, an in situ production process used to recover bitumen from oil sands.
Total Return	Calculated using the change in the trust unit price from the start of the period (including any capital appreciation or depreciation) and the total cash distributions paid during the period divided by the starting unit price.

directors

Douglas R. Martin [1,2]
President
Charles Avenue Capital Corp.
Calgary, Alberta

Edwin V. Dodge [3,9,11]
Corporate Director
Vancouver, British Columbia

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Resources Fund
Calgary, Alberta

Robert L. Normand [6,9]
Corporate Director
Rosemere, Québec

Glen D. Roane [5,10]
Corporate Director
Canmore, Alberta

W. C. (Mike) Seth [3,7]
President
Seth Consultants Ltd.
Okotoks, Alberta

Donald T. West [7,12]
Corporate Director
Calgary, Alberta

Harry B. Wheeler [5,8]
President
Colchester Investments Ltd.
Calgary, Alberta

Robert L. Zorich [4,11]
Managing Director
EnCap Investments L.P.
Houston, Texas

(1) Chairman of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chairman of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chairman of the Audit & Risk Management Committee
(7) Member of the Reserves Committee
(8) Chairman of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chairman of the Compensation & Human Resources Committee
(11) Member of the Environment, Health & Safety Committee
(12) Chairman of the Environment, Health & Safety Committee

officers

Gordon J. Kerr
President & Chief Executive Officer

Garry A. Tanner
Executive Vice President & Chief Operating Officer

Ian C. Dundas
Senior Vice President, Business Development

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Investor Relations

Rodney D. Gray
Vice President, Finance

Larry P. Hammond
Vice President, Operations

Lyonel G. Kawa
Vice President, Information Services

Jennifer F. Koury
Vice President, Corporate Services

Eric G. Le Dain
Vice President, Marketing

David A. McCoy
Vice President, General Counsel & Corporate Secretary

Daniel M. Stevens
Vice President, Development Services

Wayne G. Ford
Controller, Operations

Jodine J. Jenson Labrie
Controller, Finance

corporate information

Operating Entities Owned by
Enerplus Resources Fund

EnerMark Inc.
Enerplus Resources Corporation
Enerplus Oil & Gas Ltd.
Enerplus Commercial Trust
Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
Deloitte & Touche LLP
Calgary, Alberta

Transfer Agent
CIBC Mellon Trust Company
Calgary, Alberta
Toll free: 1.800.387.0825
Email: inquiries@cibcmellon.com

Co-Transfer Agent
Mellon Investor Services L.L.C.
Ridgefield, New Jersey

Independent Reserve Engineers
Sproule Associates Limited
Calgary, Alberta

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

DeGolyer and MacNaughton
Dallas, Texas

Stock Exchange Listings and Trading Symbols
New York Stock Exchange: ERF
Toronto Stock Exchange: ERF.un

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Denver, Colorado 80203

Telephone: 720.279.5500
Fax: 720.279.5550

For more information, visit our website: www.enerplus.com

corporate information

Enerplus Internet Site

Enerplus Resources Fund has a comprehensive website that provides investors with an immediate source of all our public information. Information that can be found at www.enerplus.com includes:

- Unit Trading Data
- Annual and Quarterly Reports
- Tax Information
- News Releases
- Recent Presentations
- 15 Minute Delayed Stock Quote
- Historical Distributions
- Distribution Reinvestment and Unit Purchase Plan
- Adjusted Cost Base Calculator
- Operational Information
- Corporate Governance Practices and Charters
- Whistleblower Policy
- Important Dates and Events
- Links to SEDAR and EDGAR filings
- Other relevant information pertaining to Enerplus Resources Fund

Annual General Meeting

Unitholders are encouraged to attend the Annual General Meeting being held on:

Friday, May 4, 2007
10:30 am mountain daylight time at
The Metropolitan Centre
333 – 4th Avenue S.W.
Calgary, Alberta

enerPLUS
RESOURCES FUND

The Dome Tower
3000, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

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